OAK RIDGE NATIONAL LABORATORY
MANAGED BY UT-BATTELLE FOR THE DEPARTMENT OF ENERGY

ORNL/TM-2011/151

Final Report

Economic Analysis of Deploying Used Batteries in Power Systems

June 2011

Prepared by

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George Andrews

UT-BATTELLE
ORNL-27 (4-00)

ORNL/TM-2011/151

Sustainable Electricity Program—Energy Storage

FINAL REPORT

ECONOMIC ANALYSES OF DEPLOYING USED BATTERIES IN POWER SYSTEM

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Date Published: June 2011

Prepared by
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Oak Ridge, Tennessee 37831-6283
managed by
UT-BATTELLE, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract DE-AC05-00OR22725

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LIST OF ACRONYMS

AC	alternating current
AEV	all-electric vehicle
BCG	Boston Consulting Group
BEV	battery electric vehicle
C&I	commercial and industrial
CES	community energy storage
CAISO	California ISO
DC	direct current
DOE	U.S. Department of Energy
DOT	Department of Transportation
EOL	end-of-life
EPRI	Electric Power Research Institute
EV	electric vehicle
HEV	hybrid electric vehicle
ICE	internal combustion engine
ISO	independent system operator
Li-ion	lithium ion
MSRP	manufacturer's suggested retail price
NiMH	nickel-metal-hydride
NYISO	New York Independent System Operator
O&M	operation and maintenance
OEM	original equipment manufacturer
PG&E	Pacific Gas and Electric
PHEV	plug-in hybrid electric vehicle
PV	present value
R&D	research and development
SETP	Solar Energy Technology Program
SNL	Sandia National Laboratory
T&D	transmission and distribution
TOU	time-of-use
UN	United Nations
UPS	uninterruptible power supply
USABC	United States Advanced Battery Consortium
VOC	variable operating cost

ACKNOWLEDGEMENTS

This study was funded by the U.S. Department of Energy through the Office of Electricity, Energy Storage Program. We thank Dr. Imre Gyuk, PhD, for supporting this activity and providing valuable input. We thank Dr. Zoltan Yung (U.S. Environmental Protection Agency) for his insights and Greg Cesiel (General Motors), Ken Srebrik (Nissan), Peter Dempster (BMW), Dr. Ronald Bailey (University of Tennessee, Chattanooga), and Tarek Abdel-Baset (Chrysler Group LLC) for their valuable suggestions and continuous support.

EXECUTIVE SUMMARY

The objective of this study is to explore the various possible markets for the secondary use of Li-ion batteries removed from electric or hybrid electric vehicles (EVs or HEVs) after they can no longer conform to vehicle specification but still have substantial functional life. This report is the first phase of the study, and the scope is limited to secondary use of Li-ion batteries in power system applications. The primary focus of this report is the cost competitiveness of these batteries for power grid applications.

Original equipment manufacturers such as General Motors, Nissan, and Toyota offer long-term warranties for the battery packs in their vehicles. The expectation is that once battery efficiency (energy or peak power) decreases to 80%, the batteries will be replaced. The rationale is that a 20% reduction in the vehicle range, imposed by the decrease in efficiency, would be unacceptable to consumers. Based on various forecasts for market penetration of plug-in hybrid electric vehicles (PHEVs) and EVs over the next 10 years, it is estimated that a large number of PHEVs and EVs will be approaching the 80% battery efficiency level by 2020. These batteries can be recycled or used in other less demanding applications provided a business case can be made for their secondary use.

For this economic analysis, data have been gathered on the projected cost of new batteries in 2020 and the projected supply of HEVs, EVs, and PHEVs over the next decade. These data were then used to determine the potential supply of batteries for secondary use and the acceptable refurbishing costs. Based on this, a proposed sale price for the secondary-use batteries has been developed. This price and the system prices for various grid applications were used to calculate potential benefits. In this analysis, the battery pack was assumed to have a lifetime of either 5 or 10 years because the secondary life is dependent largely on application.

The applications that offer the most attractive value proposition for secondary use of EV batteries over the entire range of value and cost assumptions used in this report include area regulation, transmission and distribution (T&D) upgrade deferral, and electric service power quality. Those applications should be targeted for additional in-depth analysis and initial deployment of used EV batteries as they become available in the market. However, these markets will presumably not be enough to absorb the entire volume of secondary-use EV batteries predicted for 2020 and beyond.

The cost of the applications is determined by the cost of the used batteries, balance of system cost, refurbishment cost, transportation cost, and operation and maintenance (O&M) costs. The transportation cost will depend on whether used batteries are treated as hazardous materials or hazardous waste. When calculating the cost of a particular application, the peak power requirement and the energy capacity of the storage system were defined based on similar real-world applications. For applications requiring high-energy capacity, the dominating costs are the cost of the used batteries and the cost of the transportation (if treated as hazardous waste); for applications requiring high-power, the balance of system cost and the O&M costs dominate the overall system cost.

Synergies, understood as the net benefit from using the same battery system for multiple applications at a given location, were also investigated. Selected combinations of applications must be compatible in terms of size, power-to-energy ratio, duty cycle, operation profile, and involved stakeholders. In some cases, the energy consumed/generated while charging/discharging the battery provides multiple benefits that can be directly aggregated. In other cases, battery use in one application precludes simultaneous use in another so that assumptions or simulations of how the system would be operated are required.

Individually, neither the energy time shift nor the electric supply capacity nor the renewables capacity firming applications appear as strong candidates for profitable secondary use of EV batteries. Peak versus off-peak price differentials and the cost of used batteries are crucial elements whose evolution will determine whether those types of applications could generate a positive net return by 2020. Their low power-to-energy ratio makes for expensive system installation costs which, in turn, hurt their profitability. "Stacking" energy time-shift and capacity applications only builds an attractive business case under optimistic assumptions regarding peak–off-peak price differentials, avoided capacity costs, and system costs.

A business case begins to emerge when applications with a low utilization factor, like voltage support (only a few hours over the entire operating life of the system), are combined with applications that increase the utilization factor of the system (e.g., T&D upgrade deferral and/or electric supply capacity). Then financial justification exceeds that of individual applications. Residential or commercial and industrial customers using battery energy storage for managing time-of-use tariffs and demand charges would only use them during the summer. An aggregator that would coordinate the needs of multiple customers and manage the operation of the energy storage device would be a good option for optimizing the value of such battery systems throughout the whole year.

Time of use energy management (peak shaving) is the most promising application for community energy storage (CES). Time of use energy management makes great sense where communities install energy storage systems controlled for peak shaving and indirect benefits to the distribution and transmission system such as upgrade deferral, and reserve supply capacity, may be realized. Where markets allow aggregation and smart grid communication infrastructure is implemented between utilities, ISOs, and CES systems, ISOs could aggregate and control CES units to provide several ancillary services.

1. INTRODUCTION

1.1 OBJECTIVE

The increasing cost of gasoline and the advances in technology for longer range electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) have had an impact on the market share of vehicles powered by electricity. This is in part due to the success of hybrid electric vehicles (HEVs). The most recent generation of HEVs used nickel-metal-hydride (NiMH) batteries, while the PHEV and EV powertrains are currently based on Li-ion batteries. HEVs couple gasoline engines, electric drivetrains, and batteries for a passive use of the electric drive where batteries are utilized to improve the mile per gallon efficiency of a gasoline powered vehicle. The PHEV technology, such as that used in the Chevrolet (Chevy) Volt, pushes the HEV technology one step further by designing the vehicle to solely use the electric drivetrain, after a full charge, for distances upwards of 40 miles before using an onboard gasoline engine. This is done through larger energy storage units compared to the standard HEV technology. EVs such as the Nissan Leaf have no gasoline drive. Depending on models, the range of EVs has been reported to be about 100–300 miles, with the higher mileage corresponding to the Tesla. The limited market penetration of EVs is believed to be due to limited driving range and price. The driving range is further affected by environmental conditions (e.g., under high summer temperatures, the range of the vehicle could drop significantly due to energy demands of air conditioners).

Original equipment manufacturers (OEMs) such as GM, Nissan, and Toyota offer long-term warranties for their battery packs. The expectation is that the batteries will be replaced with a fresh battery pack once their efficiency (energy or peak power) decreases to 80%. The rationale is that the 20% reduction in the range of vehicles occasioned by such a decrease in efficiency would be unacceptable to consumers. Based on various forecasts for market penetration of PHEVs and EVs over the next 10 years,[1] a large number of PHEVs and EVs will be approaching this 80% efficiency level by 2020. These batteries can be recycled or used in other less demanding applications for the rest of their useful life provided a business case can be made for their secondary use.

The secondary use of batteries is highly desirable for both economic and environmental reasons. The economic drivers include factors such as extended use of expensive chemicals and distributing battery costs on two different consumer segments. Environmental drivers include reduction in waste and reduction in the energy that would otherwise be needed to produce fresh batteries.

The objective of this study is to explore the various possible markets for the secondary use of the Li-ion batteries that will become available in 2020 and into the future. This report is the first phase of the study, and the scope is limited to secondary use of Li-ion batteries in power system applications. The primary focus of this report is the cost competitiveness of these batteries for power grid applications. To be able to compare the results of this work with previous efforts, identical assumptions will be applied in calculating the benefits.

1.2 LITHIUM ION BATTERIES

Vehicles with electric propulsion systems can be broken into three main categories as described below.

- <u>Electric vehicles</u>. EVs are also known as all-electric vehicles (AEVs) or battery electric vehicles. These vehicles are equipped with batteries, and they are propelled with an electric machine that is controlled by a motor drive. In these vehicles, the battery is the only source for propulsion. City EVs, which are small EVs designed for urban commuting, and neighborhood EVs, which are small, low-speed, low-distance vehicles, can also be included in this category because these vehicles are equipped with battery-based electric drivetrains without internal combustion engines (ICEs).

- Hybrid electric vehicles. HEVs have ICEs and battery-based electric drivetrains. Depending on the coupling of the propulsion systems (hybridization configuration), these vehicles can be classified into series, parallel, and power-split (series/parallel) HEVs. In parallel hybrids, the ICE and the electric motor are both connected to the transmission and can simultaneously transmit power to the wheels. The series hybrids usually employ an electric drive to propel the vehicle while the ICE acts as a generator to supply energy to the electric drivetrain and batteries. Power-split hybrids have a combination of series and parallel characteristics. Depending on the hybridization level, HEVs can be categorized into full, mild, and micro (start/stop) HEVs. Full hybrids can run on the gasoline powered engine, the battery, or a combination of both. Mild hybrids generally cannot be run solely on their electric motors and typically contain an oversized starter motor so that the engine can be switched off when the vehicle is idling or coasting.

- Plug-in hybrid electric vehicles. PHEVs combine features of AEVs and HEVs. PHEVs have relatively larger battery storage capacity than that of HEVs and are equipped with a plug and grid interface converter to recharge the batteries from an external source. In charge-depleting mode, a PHEV operates as an EV; the battery-based electric drivetrain solely provides the propulsion. After the state-of-charge of the battery pack decreases to a certain value, a PHEV switches to the charge-sustaining mode and operates as a regular HEV which also utilizes an ICE for propulsion. Because PHEVs use ICEs, their typical range is more than that of the EVs, and these vehicles can still operate as efficiently as HEVs in the charge sustaining mode.). Extended range EVs are included in this category even though the ICE is only used to recharge the battery, and not for vehicle propulsion.

The current generation of EVs and PHEVs use Li-ion batteries. Before continuing with the details of this study, Li-ion batteries will be described based on various chemistries and the requirements for their use in vehicles.[2,3] This information is useful for determining the viability of the determined secondary use applications.

A Li-ion battery is classified as a secondary-use battery because the battery can be cyclically discharged and recharged. This is in contrast to primary batteries that cannot be recharged. Each battery cell consists of a cathode, anode, and electrolytes. During discharge, the lithium ions move from the negative electrode to the positive electrode. An external source of energy enables lithium ions to move back to the negative electrode for recharging.

The negative electrode (anode during discharge) of the Li-ion battery is composed of carbon, with graphitic carbon as the material of choice. Fig. 1.1 depicts a typical Li-ion battery. The positive electrode (cathode during discharge) is typically made from a layered oxide (e.g., $LiCoO_2$), polyanion (e.g., $LiFePO_4$), or a spinel (e.g., $LiMn_2O_4$). The electrolyte is generally an organic carbonate containing lithium salts such as lithium hexafluorophosphate ($LiPF_6$), lithium perchlorate ($LiClO_4$), lithium tetrafluoroborate ($LiBF_4$), lithium triflate (LiO_3SCF_3), or lithium hexafluoroarsenate ($LiAsF_6$). Li-ion cells for vehicular application are arranged either in series or in parallel as modules having common terminals (or bus bars). Several such modules are then assembled to form a battery pack with an appropriate cooling mechanism in place. The number of batteries placed in series and parallel determines the voltage and current rating.

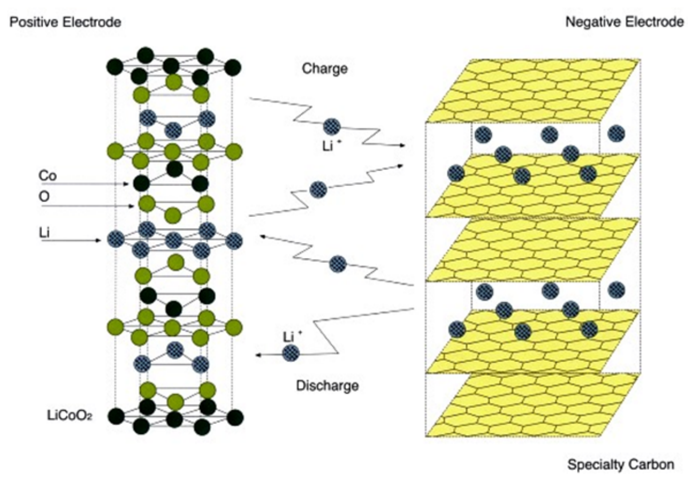


Fig. 1.1. A typical lithium ion battery.

In a typical graphite-$LiCoO_2$ battery, the electrochemistry is quite simple:

$$LiCoO_2 \rightleftarrows Li_{1\text{-}x}CoO_2 + xLi^+ + xe^-$$

$$xLi^+ + xe^- + 6C \rightleftarrows LixC_6 \,.$$

Overcharging the cell can result in oxygen loss from the positive electrode, here $Li_{1-x}CoO_2$, and decomposition of the electrolyte. Both processes lead to potential thermal runaway conditions in the battery. The thermal safety of a Li-ion cell is specific to the battery chemistry. For example, layered oxide cathodes ($LiMO_2$; M = Ni, Co, Mn) are more vulnerable to thermal runaway than are the stable olivine or spinel chemistries.

The nominal cell voltage depends on the redox couple, the cell potential, and the specific capacities of various electrode materials, as summarized in Table 1.1. The liquid electrolytes generally contain lithium salts that act as charge carriers between electrodes during charge and discharge processes. The conductivity is dependent on temperature and the composition and constituents of the electrolyte. For room temperature the conductivity of these electrolytes is in the range of 10 mS/cm. The conductivity increases by as much as 40% at 40°C and decreases slightly at 0°C.

Table 1.1. The properties of Li-ion battery electrode materials

Electrode material	Average potential difference (V)	Specific capacity (mA-h/g)	Specific energy (kWh/kg)
	Positive electrodes		
$LiCoO_2$	3.7	140	0.518
$LiMn_2O_4$	4.0	100	0.400
$LiNiO_2$	3.5	180	0.630
$LiFePO_4$	3.3	150	0.495
Li_2FePO_4F	3.6	115	0.414
$LiCo_{0.33}Ni_{0.33}Mn_{0.33}O_2$	3.6	160	0.576
$Li(Li_aNi_xMn_yCo_z)O_2$	4.2	220	0.920
	Negative electrodes		
Graphite (LiC6)	0.1–0.2	372	0.0372–0.0744
Hard Carbon (LiC6)	—	—	—
Titanate (Li4Ti5O12)	1–2	160	0.16–0.32
Si (Li4.4Si)	0.5–1	4,212	2.106–4.212
Ge (Li4.4Ge)	0.7–1.2	1,624	1.137–1.949

The chemistry of a Li-ion battery can have a significant impact on the useful life because the battery life depends on the selection of electrode materials and electrolytes.[4] The battery cell is defined as the unit containing electrodes and electrolytes in a container. A battery module is a group of cells electrically connected in series or parallel arrangement, and a battery pack contains several modules. The United States Advanced Battery Consortium (USABC) performance goals for batteries to be used in HEVs and EVs are presented in Tables 1.2 and 1.3. These goals will be referred to in succeeding chapters.

Table 1.2. FreedomCAR Energy Storage System performance goals for power-assist HEV

Characteristics	Power-assist (min)	Power-assist (max)
Pulse discharge power (kW)	25	40
Peak regenerative pulse power (kW)	200 (55-Wh pulse)	350 (97-Wh pulse)
Total available energy (kWh)	0.3 (at C_1/1 rate)	0.5 (at C_1/1 rate)
Minimum round-trip efficiency (%)	90 (25 Wh cycle)	90 (50 Wh cycle)
Cold ranking power (kW) at –30°C (three 2 s pulses, 10 rests between)	5	7
Cycle life for specified state-of-charge increments (cycles)	300,000 (25 Wh cycles; 7.5 MWh)	300,000 (50 Wh cycles; 15 MWh)
Calendar life (years)	15	15
Maximum weight (kg)	40	60
Maximum volume (L)	32	45
Operating voltage limits (Vdc)	Max ≤ 400 Min ≥ (0.55 × Vmax)	Max < 400 Min > (0.55 × Vmax)
Maximum allowable self-discharge rate (Wh/day)	50	50
Temperature range (°C)		
Equipment operation	–30 to +52	–30 to +52
Equipment survival	–46 to +66	–46 to +66
Production price ($) @ 1,000,000 units/year	500	800

Table 1.3. United States Advanced Battery Consortium goals for advanced batteries for EVs

Parameters (units) of fully burdened system	Minimum goals for long-term commercialization	Long-term goal
Power density (W/L)	460	600
Specific power—discharge, 80% depth of discharge (DOD)/30 sec (W/kg)	300	400
Specific power—regen, 20% DOD/10 sec (W/kg)	150	200
Energy density—C/3 Discharge rate (Wh/L)	230	300
Specific energy—C/3 discharge rate (Wh/kg)	150	200
Specific power : specific energy	2 : 1	2 : 1
Total pack size (kWh)	40	40
Life (years)	10	10
Cycle life—80% DOD (cycles)	1,000	1,000
Power % capacity degradation (% of rated spec)	20	20
Selling price—25,000 units @ 40 kWh ($/kWh)	<150	100
Operating environment (°C)	–40 to +50 20% performance loss (10% desired)	–40 to +85

Table 1.3. (continued)

Parameter (units) of fully burdened system	Minimum goals for long-term commercialization	Long-term goal
Normal recharge time	6 hours (4 hours desired)	3 to 6 hours
High rate recharge	20%–70% state-of-charge (SOC) in <30 minutes @ 150 W/kg (<20 min @ 270 W/kg desired)	40%–80% SOC in 15 minutes
Continuous discharge in 1 hour—No failure (% of rated energy capacity)	75	75

For PHEVs, the end-of-life (EOL) energy storage system goals are defined in Table 1.4.

Table 1.4. United States Advanced Battery Consortium (USABC) requirements for end-of-life (EOL) energy storage systems for plug-in hybrid electric vehicles

Characteristics at EOL	High power/energy ratio battery	High energy/power ratio battery
Reference equivalent electric range (miles)	10	40
Peak pulse discharge power (kW)	450	380
Peak regen pulse power (kW)	300	250
Available energy for CD (charge depleting) mode, 10 kW rate (kWh)	3.4	11.6
Available energy for CS (charge sustaining) mode (kWh)	0.5	0.3
Minimum round-trip efficiency, USABC HEV cycle (%)	90	90
Cold ranking power at –30°C, 2s, 3 pulses (kW)	7	7
CD life/discharge throughput (cycles/MWh)	5,000/17	5,000/58
CS HEV Cycle life, 50 Wh profile (cycles)	300,000	300,000
Calendar life, 35°C (years)	15	15
Maximum system weight (kg)	60	120
Maximum system volume (L)	40	80
Maximum operating voltage (Vdc)	400	400
Minimum operating voltage (Vdc)	>0.55 × Vmax	>0.55 × Vmax
Maximum self-discharge (Wh/day)	50	50
System discharge rate at 30°C (kW)	1.4 (120V/15A)	1.4 (120V/15A)
Unassisted operating and charging temperature range (°C)	–30 to +52	
Survival temperature range (°C)	–46 to +66	–46 to +66
Maximum current, 10 s pulse (A)	300	300
Maximum system production price @ 100,000 units/year	$1,700	$3,400

1.3 PROPERTIES OF BATTERY PACKS IN REPRESENTATIVE VEHICLES

The current specifications for batteries being used in the Chevy Volt PHEV, Nissan Leaf EV, and Toyota Prius PHEV are presented in Tables 1.5–1.7. These specifications will be referred to in succeeding chapters.

Table 1.5. Chevy Volt PHEV Li-Ion Battery Specifications[5–7]

Parameter	Value
Nominal battery voltage (V)	370
Number of cells	288
Energy storage capacity (kWh)	16
Nominal power (continuously) (kW)	55
Peak power (for a short period of time) (kW)	115
Maximum current (A)	400
Battery weight (lb)	436

Table 1.6. Nissan Leaf EV Li-Ion Battery Specifications[8–10]

Parameter	Value
Nominal battery voltage (V)	345
Number of cells	192
Energy storage capacity (kWh)	24
Nominal power (continuously) (kW)	62
Peak power (kW)	90
Maximum current (A)	260.87
Battery weight (lb)	660

Table 1.7. Toyota Prius PHEV (upcoming) Li-Ion Battery Specifications[11,12]

Parameter	Value
Nominal battery voltage (V)	345.6
Number of cells	288
Energy storage capacity (kWh)	5.2
Nominal power (continuously) (kW)	40
Peak power (kW)	60
Maximum current (A)	173.61
Battery weight (lb)	330

1.4 PREVIOUS STUDIES

Studies on the secondary use of batteries started after the success of HEVs, especially the Toyota Prius. The first comprehensive study, from Sandia National Laboratory (SNL), published in March 2003, evaluated secondary use of NiMH batteries.[13] A second report from SNL in February 2010 focused primarily on energy storage for the electricity grid and presented an assessment of market potential and benefits analysis.[14] The U.S. Department of Energy (DOE) Electricity Advisory Committee and the Electric Power Research Institute (EPRI) have also issued white papers on electricity energy storage technology options in Dec. 2008 and Dec. 2010, respectively.[15,16]

This report builds on the previous work by SNL and EPRI and explores the possibility of secondary use of Li-ion batteries that will become available in 2020 after reaching EOL status for EV and PHEV applications.

1.5 METHODOLOGY

The first step in conducting the analysis for secondary-use batteries included gathering the available data on the projected cost of new batteries in 2020 and the projected supply of HEVs, EVs, and PHEVs over the next decade. These data were used to determine the potential supply of batteries for secondary use and for generating acceptable refurbishing costs. Based on this, a proposed sale price for the secondary-use batteries was developed, and information on system prices for particular applications was provided.

The next step was to analyze the potential benefits of energy storage for the electric power grid. In this analysis, the battery pack was assumed to have a lifetime of either 5 or 10 years because the remaining useful life is dependent on its secondary application.

The decision on the potential application of Li-ion batteries for secondary use applications in the power system can then be addressed through a cost-benefit analysis of individual applications. Synergistic benefits between energy storage applications are briefly explored.

1.6 POLICY BARRIERS

In addition to technical and economic barriers to application of secondary-use lithium ion energy storage devices to the electric power grid, a number of policy issues need to be considered. Varying regulatory treatments can influence the market penetration and acceptance of technology. A good example of regulatory influence is the introduction of emission treatment catalysts to alleviate environmental impacts of emissions. The regulatory requirements have ensured 100% acceptance of this technology since their introduction in 1975.

The policies that can impact the supply of used batteries include the various policies in support of EVs, HEVs, and PHEVs of not only the U.S. government but also other governments. The subsidies for installing or adding Li-ion battery manufacturing capacity, the research support for next generation batteries, corporate average fuel economy standards, U.S. Environmental Protection Agency regulatory requirements for emissions, and tax incentives to consumers for purchase of EVs, HEVs, and PHEVs can impact market penetration of these vehicles, which in turn can impact the supply of secondary-use batteries.

Investment tax credits and a favorable environment for distributed and community application of energy storage will have a major impact on the market penetration of energy storage in electric grid applications. Another example of a regulatory action that improves the prospects for deployment of energy storage in the electric grid is the Federal Energy Regulatory Commission's Order 890 (http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf). This order requires regional transmission organizations and independent system operators (ISOs) to evaluate services provided by nongeneration resources, such as demand response and storage, on a comparable basis to services provided by generation resources in meeting mandatory reliability standards. As a result of this order, ISOs are modifying the existing ancillary service and capacity market rules to enable wider participation of resources. This includes the battery systems under examination in this report. Allowing energy storage resources to participate opens up new markets and potential revenue streams for energy storage technologies (e.g., capacity payments).

2. ECONOMIC ANALYSIS

As discussed in the first chapter, Li-ion batteries are currently the batteries of choice for emerging electric propulsion applications. The predominant batteries are based on lithium-cobalt oxide, but other chemistries such as lithium-nickel-cobalt-aluminum oxide, lithium-manganese spinel, lithium titanate, and lithium-iron phosphate are also available. Due to inherent safety considerations, all lithium battery chemistries require careful monitoring, balancing, and cooling systems to control the reaction chemistry and prevent thermal runaways. The value chain for electric car batteries involves several steps. First, the components such as cathode, anode, binder, electrolyte, and separator are manufactured. The components are then assembled into single cells which are configured into modules with some electronic management. The modules are assembled into battery packs with systems that manage power, charging, and temperature. The battery packs are then integrated into vehicles using battery-car interface.

In this section, the projected supply of used batteries, projected cost of new batteries, and refurbishing costs in several scenarios are summarized to determine the selling price range for used batteries. In a typical economic analysis, the price of the used battery is dependent on the supply-demand curve; however in this case, the upper limit of the price will be determined by the price of the new battery, as described below and shown in Fig. 2.1.

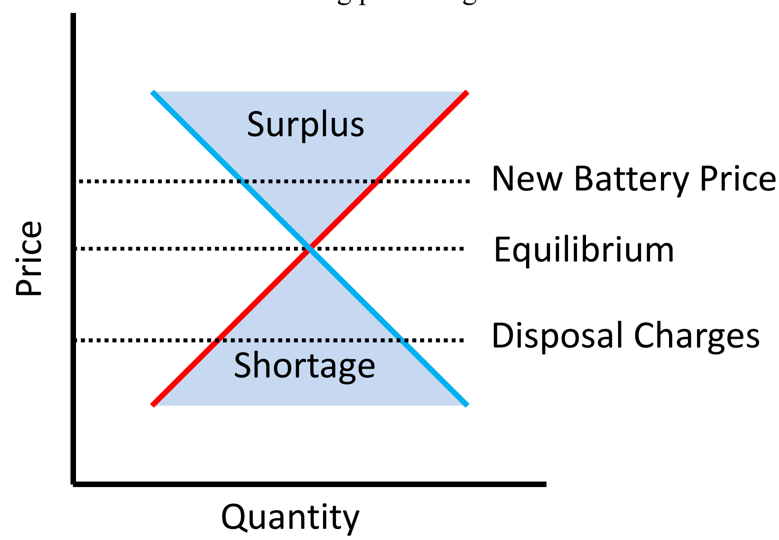


Fig. 2.1. Factors controlling used battery price.

- A high demand for batteries and a low supply of used and new batteries will lead to a price premium for the suppliers of batteries.
- A balance between supply and demand will allow the market to set the price for the used batteries. This price will be lower than the price for new batteries because the consumer will demand a price reduction for the used batteries. Thus the prevailing price of a new battery will be the upper limit for the price of the used battery.
- A surplus of new and used batteries will suppress the price of batteries in the marketplace in the short run. If there is no valid use for such batteries in the secondary market, the lower limit of the price of the used battery will be defined by the disposal cost to OEMs (either to a land refill or recycling center).

Quite obviously, economic principles dictate that high demand will interest new manufacturers to enter the market, and a surplus will lead to manufacturers leaving the market. Over time, there will be balance in the market. Thus, the price of used batteries will be lower than that of new batteries over time.

If there is no secondary market for used batteries, they will be disposed as hazardous materials or hazardous waste depending on the status of the used batteries. The cost to OEMs will vary depending on the location and ownership of landfills. At present, the cost of recycling is not well-defined but depends on the available processes to recover lithium and cobalt metals as well as separators. In either scenario, the OEMs will not be able to give away used batteries for free. Hypothetically, if OEMs give batteries away for free, for an application of used batteries to become economically attractive, end users must consider recycling/disposal costs. In this scenario, end users pay for recycling/disposal at the end of the useful life of the used batteries. Unfortunately, good estimates of recycling/disposal are not available, but the USABC Demo cost model mentions $50 recycling cost for a 9 kWh battery. Thus, the lower limit of battery price can be $5.55.

It should be obvious that secondary batteries will not sell at or near the upper or lower limit of the price. If used batteries are selling near the upper limit of the price, end users will opt for new batteries. The lower limit price scenario becomes valid only if there is no significant market for secondary use.

With the emphasis on electric drive vehicles in recent years, several studies have appeared forecasting the price of batteries and availability of vehicles. From the projected vehicle production, the supply of used batteries can be deduced. The following sections summarize the analysis of the price, supply, and demand of/for used batteries.

2.1 COST PROJECTIONS FOR NEW BATTERIES

USABC has set targets for energy storage devices for electric propulsion as follows.

- The minimum goal for the selling price is less than $150/kWh for 25,000 units at 40 kWh.
- A long-term goal of $100/kWh for 25,000 units at 40 kWh is also sought.

The Boston Consulting Group (BCG) report *Batteries for Electric Cars: Challenges, Opportunities, and the Outlook to 2020,* published in 2010, provides an estimate for the projected cost of batteries in 2020.[17] According to this report, the current cost of a Li-ion battery pack, as sold to OEMs, is between $1,000/kWh and $1,200/kWh, and a price reduction to $150/kWh will be challenging in view of the current technology options. Based on the analysis conducted by BCG analysts, a line-item model for the individual component costs involved was created in making a battery in 2009 and assigned variables that can influence each component cost under a given production level. This cost structure includes a complete bill of materials, direct and indirect plant labor, equipment depreciation, research and development (R&D), scrap rates, and overhead markup. In forecasting battery cost, BCG anticipates that active materials and purchased parts will make up nearly half of overall costs in 2020; processing and depreciation will each represent another 10% of cost; and R&D, markup, etc. will account for the remaining 30% of cost. An annual production volume for an individual supplier of about 73 million cells and 1.1 million battery packs was assumed. Based on the BCG analysis, a cost reduction of 60%–65% is expected by 2020. Thus a 15 kWh battery pack which currently costs $990 to $1,220/kWh will cost OEMs $360/kWh to $440/kWh by 2020.

For purposes of this study, the price of a used battery cannot exceed the price of a new battery in 2020, regardless of the purchase price in 2010 (assuming a 10-year life of battery based on 10-year warranty from OEMs), because it is assumed the consumer will want an additional price reduction for used batteries. Therefore, a floor price for used batteries of 50% of the USABC cost target for new batteries was applied and a ceiling of 50% of the BCG cost projection for new batteries. Thus, a competitive price for a used battery will range between $75/kWh and $220/kWh.

2.2 SUPPLY OF BATTERIES

During the past year, several reports have been published on the estimated market for HEVs, PHEVs, and EVs. The BCG report anticipates 14 million EVs will be sold in China, Japan, and the United States by 2020.[17] A recent report from DOE forecasts a total of 1 million EVs (PHEVs and EVs) by 2015, which is aligned with President Obama's goal of putting 1 million vehicles on the road by 2015.[18] The breakdown per year is shown in Fig. 2.2.

A thorough analysis of HEVs, PHEVs, and EVs has been carried out by J.D. Power and Associates, and the results are available in a report titled *Drive Green 2020: More Hope than Reality* published in November 2010.[1] According to this report, the number of passenger vehicles in the world exceeded 500 million units in 1995, increased to 896 million units by 2010, and is expected to climb to 1.2 billion by 2015. Practically all of these vehicles are based on ICE technology. In 2010, the total number of vehicles sold globally was expected to reach 70.9 million, with only 5.2 million units using some form of electric propulsion. The global and U.S. outlooks for HEV+PHEV and EV vehicles for the next decade are shown in Figs. 2.2–2.6.

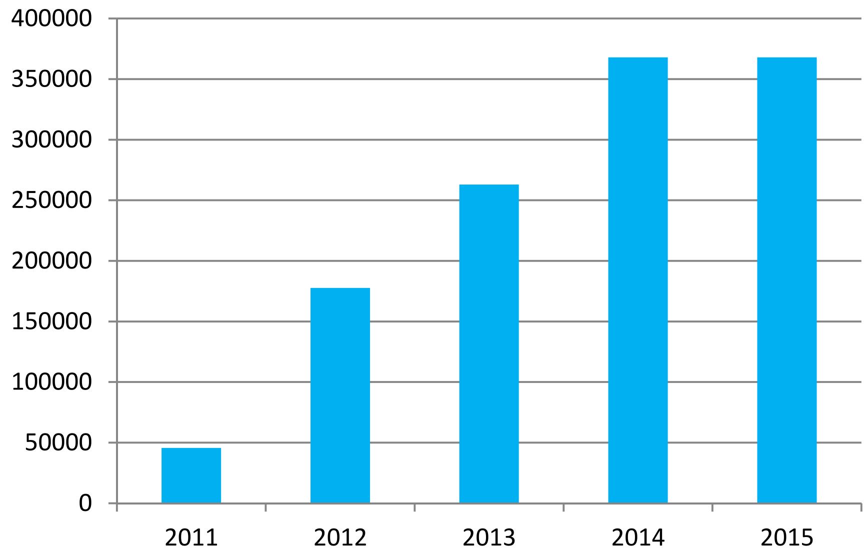


Fig. 2.2. Electric vehicles by 2015 from the U.S. Department of Energy 2011 status report.[18]

The relatively minor market penetration of electric-propulsion-based vehicles is primarily due to the associated price premium. As pointed out in the *Drive Green 2020* report, the top four best selling conventional (gasoline powered) models (Toyota Corolla, Ford Focus, Honda Civic, and Chevy Cruze) in the United States have a manufacturer's suggested retail price (MSRP) in the United States in the $15,400 to $16,200 range, with projected sales of 240,000–315,000 units each. In contrast, the best selling Toyota Prius HEV is expected to have an MSRP of $22,800 and projected sales of about 145,000 units. Thus the price premium for HEVs is 40%–48%.

From these data, the supply of used batteries can be calculated by assuming EOL at 5 years and 10 years. The rationale for 10 years is based on the warranty being offered by OEMs for the battery packs. The 5-year time span represents a low end of useful life.

The service life of 5 years will require changing battery packs every 5 years, and 1,423,000 used battery packs will be available in 2020 in the United States. The service life of 10 years will reduce the availability of used battery packs to 295,000 in the United States in this time frame.

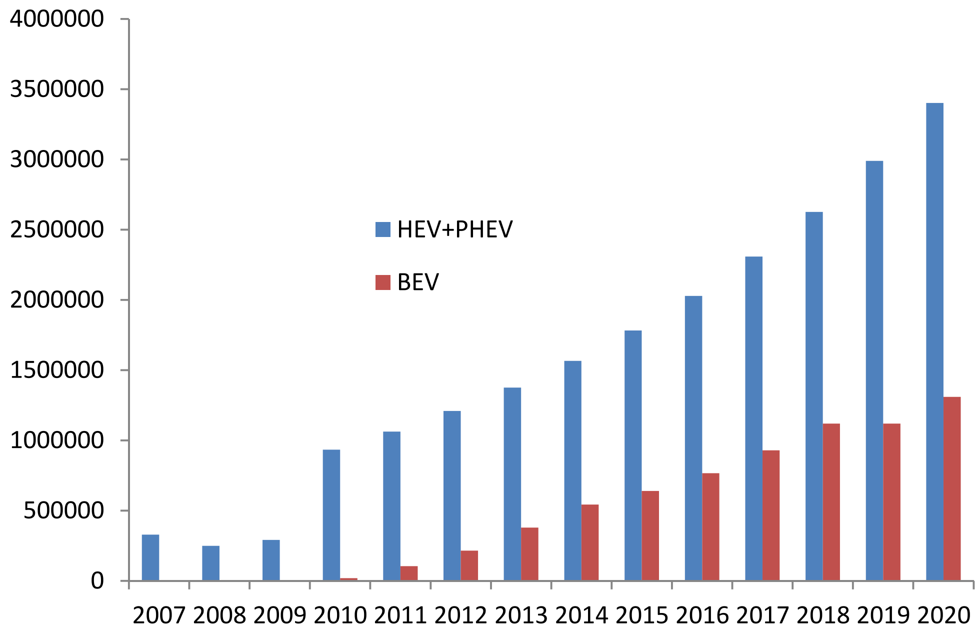


Fig. 2.3. Projected U.S. market for electric-propulsion-based vehicles based on the data from the *Drive Green 2020* report.[1] The data for 2015, 2018, and 2019 are calculated for linear growth.

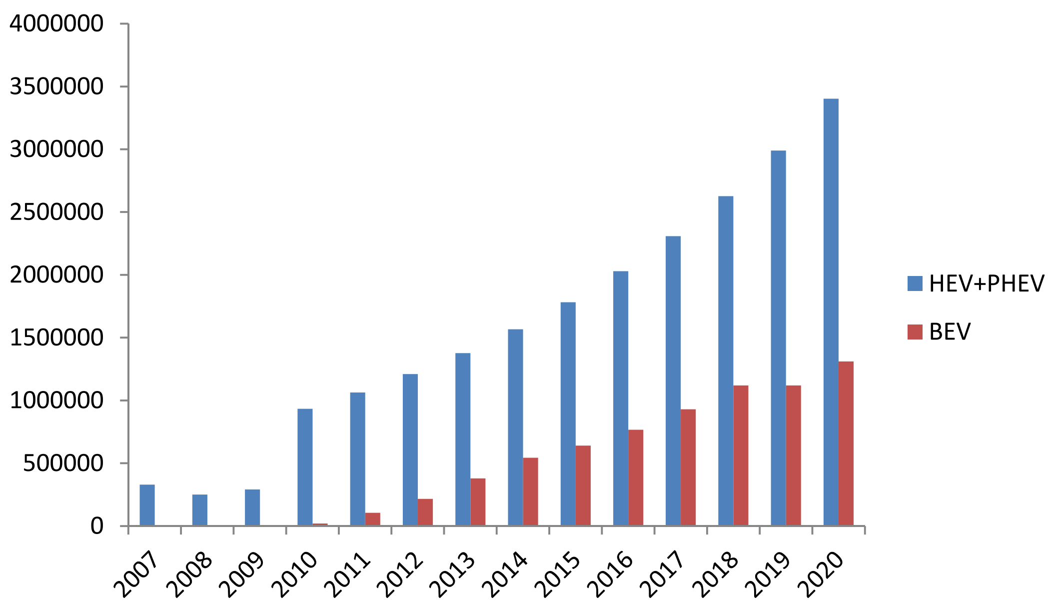


Fig. 2.4. Projected global market for electric-propulsion-based vehicles based on the data from the *Drive Green 2020* report. The data for 2015, 2018, and 2019 are calculated for linear growth.

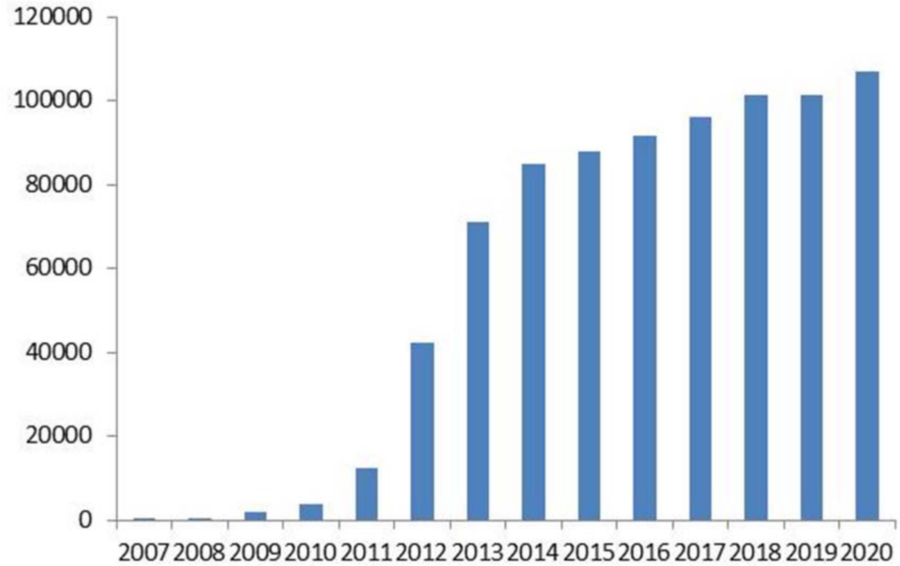


Fig. 2.5. Projected electric-propulsion-based vehicles requiring battery pack change in 2020 in the United States.

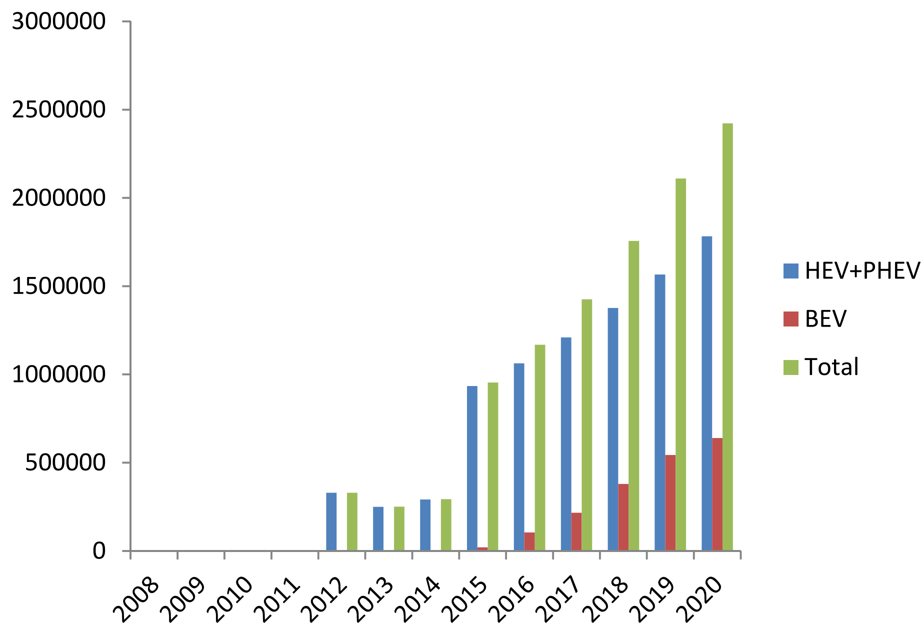


Fig. 2.6. Projected global electric-propulsion-based vehicles requiring battery pack change in 2020.

2.3 REFURBISHING COSTS

Considering that battery packs already contain systems that manage power, charging, and temperature and sensors to monitor the health of batteries, the refurbishing cost can be avoided or limited if the data collected by service stations from the battery sensors can be used to remove the modules that have deteriorated from the battery pack. The question remains whether there should be standardization of sensors to facilitate this.

The refurbishing cost of the used battery packs can be estimated based on the costs associated with plants that will do the refurbishing. This requires the following assumptions.

- About 10 plants in strategically chosen locations will be able to do the refurbishing on the 1.4 million used batteries that are expected to become available in 2020.
- Each plant will handle about 142,300 used batteries per year.
- A hypothetical facility of 10,173 ft^2 of space, similar in layout to the one described by Cready et al.,[13] is adequate for testing and refurbishing the battery packs.

The fixed costs of the plant are as follows.

Staff. The plant will be run by a plant manager and supported by a staff of 2 supervisors, 1 electrical engineer, 1 office manager, 20 technicians, 1 forklift driver, 1 marketing manager, and 1 operations manager, as depicted in Table 2.1. The specialized positions include one forklift driver and one janitor. The salaries for staff are from the U.S. Department of Labor Bureau of Labor Statistics *National Compensation Survey* (http://www.bls.gov/eci/) for transportation vehicle parts manufacturers, and benefits are from the U.S. Department of Labor Bureau of Labor Statistics, *Employer Costs for Employee Compensation* for Quarter 2, 2010 (http://www.bls.gov/news.release/ecec.toc.htm) and are 29.4% of total compensation.

Table 2.1. Employee costs

Category	Employees	Salary ($)	Salary + benefits ($)	Total ($)
Plant Manager	1	173,860	224,975	224,975
Supervisors	2	67,800	87,733	175,466
Electrical Engineer	1	80,730	104,465	104,465
Office Manager	1	53,880	69,721	69,721
Technicians				
Testing	8	37,120	48,033	384,266
Pack Assembly	12	26,850	34,744	416,927
Forklift driver	1	46,300	59,912	59,912
Security Guards	3	30,860	39,933	119,799
Marketing Manager	1	104,000	134,576	134,576
Operations Manager	1	111,660	144,488	144,488
Janitor	1	28,090	36,348	36,348
Total				1,870,943

General and administrative costs. Rent, supplies and computer leases, legal transactions, telecom, insurance, furnishings, maintenance, and outsourced human resource services will fall in this category as shown in Table 2.2. The rent of the facility will be a major component of general and administrative costs.

Table 2.2. General and administrative costs

Category	Cost ($)
Rent ($60/ft^2/year)	610,380
Supplies and computer leases	62,500
Legal transactions	125,000
Telecom	62,500
Insurance	125,000
Furnishings	93,750
Maintenance	25,000
Outsourced human resource services	62,500
Total	1,166,630

Travel, packaging, transportation, and unexpected costs need to be added to the fixed cost category as shown in Table 2.3.

Table 2.3. Travel and transportation costs

Category	Units	Cost ($)	Total ($)
Travel		50,000	50,000
Packaging	80	50	4,000
Transportation			
Driver		29,940	29,940
Truck		70,000	70,000
Unexpected		200,000	200,000
Total			353,940

Tooling. Test equipment and materials handling costs will be in this category. Testing of 142,300 used battery packs will require battery cycle and pulsed test units and computers as shown in Table 2.4. In addition, a conveyer belt and lifting equipment will likely be required.

Table 2.4. Tooling and equipment costs[a]

Category	Units	Cost ($)	Total ($)
Test equipment			
Bitrode Model MCN 16-40-40 battery cycler	24	52,995	1,271,880
Bitrode Model RCN1-200-24 pulse test unit	6	9,696	58,176
Computers	6	8,770	52,620
Materials handling			
Conveyors	1	34,992	34,992
Module lifting equipment	8	1,212	9,696
Storage racks	1	6,280	6,280
Nissan PE30 YSC forklift	1	22,537	22,537
Total			1,456,181

[a]The costs are from ref updated to 2010 dollars (conversion factor of 1.212 from the Consumer Price Index).

Thus, the total fixed cost for the 142,300 used battery packs will be $4,847,694 or $34.07 per pack. Because a new Nissan Leaf (a typical EV) has energy storage capacity of 24 kWh, the used system taken out from it will have energy storage capacity of 19.2 kWh (80%). Therefore, if all battery packs were from the Nissan Leaf, the fixed price for refurbishing would be $1.77/kWh. However, if all used batteries were from the Chevy Volt, they would have energy storage capacity of 12.8 kWh (80% of energy storage capacity of a new 16 kWh pack), and the fixed price for refurbishing would be $2.66/kWh.

Transportation cost depends on the classification of batteries as either hazardous materials or hazardous waste. As hazardous materials, used batteries can be transported from dealer to refurbishing factory by truck, and the driver can be an employee of the refurbishing company. The variable costs are gasoline and maintenance only. The fixed costs of driver and truck will add only a few cents per kilowatt-hour to the fixed cost.

As hazardous waste, the used batteries will be subject to DOT regulations. The transportation regulations (Appendix A) have been summarized by Ultralife Corporation and can be downloaded from its website (http://ultralifecorporation.com/batteries/).[19]

The following information is from the Ultralife report *Transportation Regulations for Lithium, Lithium-Ion and Lithium-Ion Polymer Cells and Batteries,* available on the website.

> "Lithium and Lithium-ion cells and batteries are regulated in the U.S. in accordance with Part 49 of the Code of Federal Regulations (49 CFR Sections 100–185) of the U.S. Hazardous Materials Regulations (HMR). Section 173.185 and the Special Provisions contained in Section 172.102 provide information on the exceptions and packaging for shipping based on details of weights, tests and classifications. The hazardous materials table in Section 172.101 also provides related shipping information. The Office of Hazardous Materials Safety, which is within the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA), is responsible for writing the U.S. regulations that govern the transportation of hazardous materials (also known as dangerous goods) by air, rail, highway and water and drafting the regulations that govern such materials. These regulations are based on the UN *Recommendations on the Transport of Dangerous Goods Model Regulations* and UN *Manual of Tests and Criteria*."

The shipping regulations are given in Table 2.5.

Based on the mass of lithium in the anode of a lithium metal or lithium alloy cell or battery or equivalent lithium content (for Li-ion cells and batteries), the shipping regulations outlined in Table 2.5 are currently in effect.

For small and medium batteries, the variable costs are those associated with T1–T8 tests and ordinary transportation by truck. Large batteries must pass the T1–T8 tests and be shipped as class 9 hazardous materials. The T1–T8 tests are as follows.

- T1: Altitude Simulations—Store at 11.6 kPa for 6 hours at 20°C.
- T2: Thermal Test—Perform 10 cycles between 75°C and –40°C, 6 hours per cycle with no more than 30 minutes between cycles, and then observe for 24 hours.
- T3: Vibration Test—Sinusoidal Waveform with a logarithmic sweep between 7 Hz and 200 Hz and back to 7 Hz in 15 minutes. The cycle must be repeated 12 times for a total of 3 hours for each of three mutually perpendicular mounting positions of the cell or battery.

- T4: Shock Test—Half-sine shock of peak acceleration of the positive direction and 3 shocks in the negative direction of three mutually perpendicular mounting positions for a total of 18 shocks.
- T5: External Short Circuit Test—After stabilizing at 5°C, apply an external resistance of less than 0.1 ohm for 1 hour and then observe for 6 hours.
- T6: Impact Test—Place a 15.8 mm diameter bar across the sample and then drop a 9.1 kg mass from a height of 61 cm onto the bar and then observe for 6 hours.
- T7: Overcharge Test—Charge at twice the manufacturer's recommended maximum continuous charge current for 24 hours and then observe for 7 days.
- T8: Forced Discharge Test—Force discharge at an initial current equal to the maximum discharge current specified by the manufacturer and then observe for 7 days.

Table 2.5. Shipping regulations

Primary cell/battery max. Li content	Li-ion and polymer cell/battery max. Li content	Shipping classification/testing	Special packaging/ markings	Battery sizes
1.0/2.0 grams	1.5/8.0 grams	Excepted/T1–T8[a]	Yes[b]	Small
5.0/25 grams	5.0/25 grams	Class 9/Ti–T8[c,d]	Yes[e]	Medium
>5.0/>25 grams	>5.0/>25 grams	Class 9/Ti–T8[f,d]	Yes[g]	Large

[a]All cells and batteries must pass UN T1–T8 tests.
[b]Packages containing more than 12 batteries or 24 cells must meet certain packaging, marking, and shipping paper requirements.
[c]Cells and batteries must pass UN T1–T8 tests and must be shipped as Class 9 hazardous materials unless transported by motor vehicles or rail car.
[d]49 CFR 173.185(a) allows for a cell or battery that was first transported prior to January 1, 2006, and is of a type tested pursuant to the UN *Manual of Tests and Criteria,* Third Revised Edition, 1999, need not be retested.
[e]Requires Class 9 markings, labels, specification packaging, and shipping papers unless transported by motor vehicles or rail car.
[f]Must pass UN T1–T8 tests and be shipped as a Class 9 hazardous material.
[g]Requires class 9 markings, labels, specification packaging, and shipping papers.
Source: Ultralife, *Transportation Regulations for Lithium, Lithium-Ion and Lithium-Ion Polymer Cells and Batteries,* 16 December 2010.

For small and medium batteries, a truck and driver cost has been included in the fixed cost. The variable cost is the cost of T1–T8 tests.

For large batteries (i.e., the cells and batteries contain more than 5.0 g and 25.0 gram lithium content, respectively), the additional transportation cost for batteries under DOT 49 CFR, 173.185(d) can be estimated as follows.

1. Batteries should be packaged in a DOT approved poly pail, poly drum, or lined steel drum.
2. All battery terminals must be covered or taped to transport.
3. $3.85/pound for Category 4 Batteries (Reactive)—lithium ion, lithium metal, magnesium.

The $3.85 per pound transportation cost is based on discussions with a lithium battery recycling company. The total cost of battery transport for the Chevy Volt will be 400 × 3.85 = $1,540 or $120.31/kWh. The per kilowatt-hour figure is obtained by dividing $1,540 by 80% of the fresh battery capacity of 16 kWh. For the Nissan Leaf, the transportation cost will be $2,541 for the total pack or $132.34/kWh. It should be quite obvious that a transportation cost of $120–$132 (excluding the cost of T1–T8 testing) will practically make the secondary use of batteries nonviable.

Gaines and Nelson have carried out a study of materials demand for Li-ion batteries and recycling issues (http://www.transportation.anl.gov/pdfs/B/626.PDF) and determined that batteries for all categories of electric propulsion contain enough lithium to be classified as "large batteries."

As suggested in the beginning of this section, onboard diagnostics can make refurbishing unnecessary and thereby make the secondary use of batteries more viable.

2.4 POWER ELECTRONICS

In addition to the cost of batteries, the system cost includes cost of the power electronics converter for grid connection.

The cost of the inverter includes all the wiring costs for the connections of battery packs and/or modules (for series/parallel connections for desired voltage and current levels) and the cost of the inverter's control system (digital signal processor for inverter control). As the entire pack from a vehicle will be acquired, the wiring costs will be minimal for the internal connections. In addition, the packs taken from the vehicle will include the voltage, current, and temperature sensors, which will be used in the secondary application, too. Therefore, the costs of the sensors can be deducted from the cost of a regular inverter including necessary sensors. Furthermore, the battery pack in the vehicle will be equipped with required thermal management systems (forced air cooling, heat sink, etc.) and the required pack enclosure. Therefore, the cost of the packing material and the cost of the thermal management unit have not been included in the cost of the power electronic converter.

Although all the cost components of the complete storage system are based on dollars per kilowatt-hour, the cost of the power electronics should be based on the power rating. Therefore, the cost of power electronics is given in dollars per kilowatt. Grid connected photovoltaic applications are similar to grid connected battery applications in terms of power electronic conversion systems because in both applications the direct current (DC) input is inverted to alternating current (AC) output at required voltage and frequency. The only difference is the operation of the control system, which does not have any impact on the cost of the power electronics. According to SolarBuzz, a solar market research and analysis company, the current inverter cost is $0.715/W ($715/kW) as of May 2011.[20] This cost is based on the average of all current retail prices from inverter manufacturers and weighted according to the power level. In this average pricing method, all the global inverter prices, in U.S. dollars, are aggregated into a single index. The cost target of the DOE Office of Energy Efficiency and Renewable Energy Solar Energy Technology Program (SETP) is $0.10/W ($100/kW) by 2020, including the inverter warranty and the control system functionality.[21] The DOE Vehicle Technologies Program cost target for power electronics is $0.012/W ($12/kW) peak by 2015 and $0.008/W ($8/kW) by 2020.[22] The same targets were also identified in the DOE *Electrical and Electronics Technical Team Roadmap*.[23] Based on these DOE targets, high and low values for power electronics costs can be estimated at $100/kW and $8/kW, respectively. In a report prepared by Navigant Consulting Inc., experience curves models were developed to determine the relationship between cost of production and production volume, which indicates the level of experience in power electronic product development.[24] In the experience curve models, the cost of production declines by a constant percentage with each doubling of the total number of units produced. This cost reduction rate is called the "learning rate" and typically ranges from 0% to 35% depending on various technologies. Learning rate typically identifies the rate of cost reduction as the number of units produced increases. For the inverter development technology, the typical value of the learning rate is 10%.[25] Based on 10% and 20% experience learning rates, the relationship between the cumulative production and the production cost percentage is presented in Fig. 2.7.

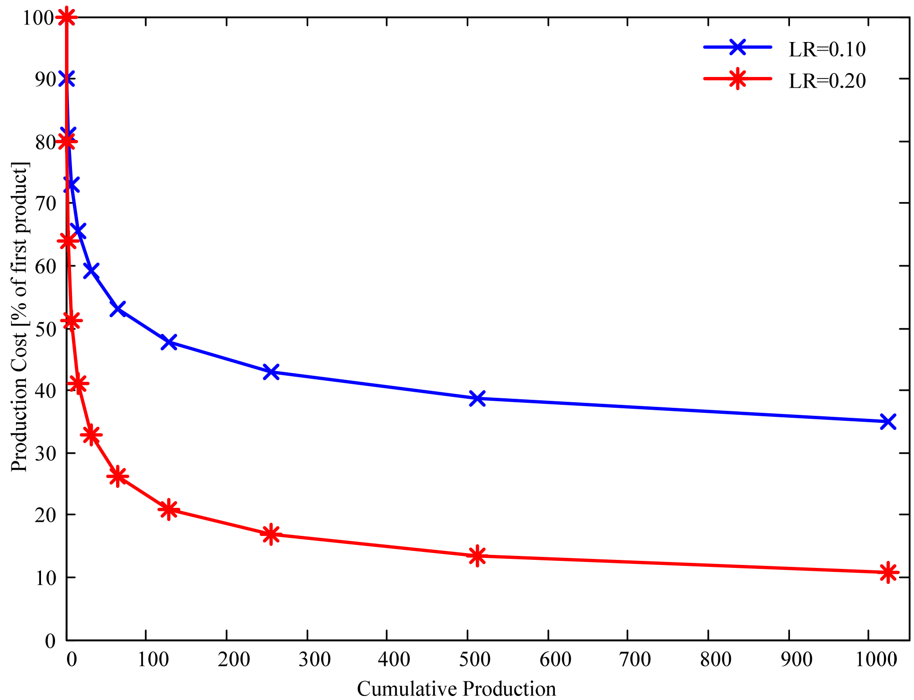


Fig. 2.7. Relationship between cumulative production and production cost based on learning rates (LRs) of 10% and 20%.

According to the analysis in Fig. 2.7, the cost of the inverter is expected to decrease by about 50% if the units produced reaches 100 for a particular application. To have a realistic cost reduction percentage, a learning rate of 10% has been applied to the cost of power electronics targeted by DOE's SETP. Therefore, if 100 units were produced for a particular application, the cost of the power electronic converter would decrease to \$50/kW. Therefore, the final high value of power electronics cost is \$50/kW, whereas the low value of power electronics cost has been estimated at \$8/kW.

Operation and maintenance (O&M) costs include the periodic and unscheduled maintenance, repair, or replacement of failed or damaged battery packs and the maintenance of the power electronic converter. The annual O&M cost is estimated based on a similar system; the O&M cost of an existing system is divided by the power rating to obtain the dollars per kilowatt per year value. The annual O&M cost does not include the recharging costs of the batteries as the recharging costs will be application dependent. The annual O&M cost used here considers the hardware related O&M costs rather than the application related operational costs. In Sects. 5 through 9, revenue stream, cost stream, and the net revenue of the system will be presented for particular applications. Eyer and Corey[14] and Klein[26] determined the typical O&M cost to be \$10/kW-year. However, Rittershausen and McDonagh[27] found \$10,000 annual O&M costs for a 2 MW Li-ion-battery-based energy storage application, which results in \$5/kW-year O&M cost. Therefore, for this study, the high and the low value of O&M costs are considered to be \$10/kW-year and \$5/kW-year, respectively. It should be noted that this also matches the assumptions of the EPRI report on electricity energy storage technology options.[16] In the EPRI report, it is stated that the O&M costs were difficult to obtain or unknown for most technologies; therefore, an assumption of roughly 0.5% to 2.0% of the capital costs were used to represent the annual fixed O&M costs in dollars per kilowatt-year. Considering a lifetime of 5 years for the secondary application of batteries, the fixed annual O&M costs can be referred to the capital cost by multiplying the annual O&M cost by the expected lifetime. Therefore, the capitalized O&M costs used for this study are \$50/kW (high value) and \$25/kW (low value).

2.5 DEMAND

The demand for used batteries is highly application specific and difficult to estimate. However, a maximum potential generic demand for renewables can be estimated by using a set of simple assumptions resulting in a maximum potential demand for renewables applications. For this study, the following assumptions were used.

- Twenty percent of the 1,200 GW power generation capacity in the United States in 2020 will be wind energy.
- Half of the wind-based generation may go out at the same time.
- To hold sufficient replacement capacity for 30 minutes, 120 GW of battery storage will be needed.
- For sustaining operation for 3 hours, 720 GW of battery storage will be needed.

Based on a battery pack from a Nissan Leaf (a typical EV), the used system will have energy storage capacity of 19.2 kWh (80% of new). There will be a demand of 3.125 M battery packs for 30-minute storage and/or 18.75 million battery packs for 3 hours if the battery packs are from a Nissan Leaf or cars with equivalent energy storage capacity.

Based on used battery packs from a Chevy Volt, the system will have energy storage capacity of 12.8 kWh. Thus, there will be a demand for 4.68 million and 28.12 million battery packs for 30 minute and 3 hour storage, respectively.

2.6 SYSTEM COST

The total system cost for this analysis has been calculated to include the price of batteries, transportation cost, power electronics cost, and O&M cost. It should be obvious that the price of batteries depends on the supply, demand, and the price of new batteries. Table 2.6 presents the summary of unitary system costs including the high and low value of the itemized costs for power system-connected energy storage systems employing used batteries.

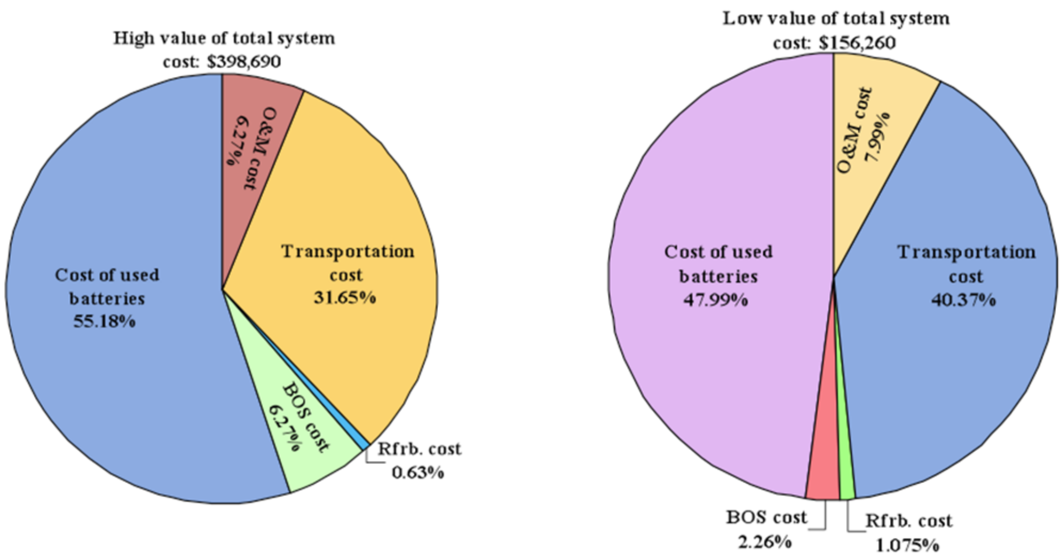
Table 2.6. Summary of costs

	Cost of used batteries ($/kWh)	Balance of system cost ($/kW)	Refurbishment cost ($/kWh)	Transportation cost ($/kWh)	Operation and maintenance cost ($/kW)
High value cost	220	50	2.52	126.17	50
Low value cost	75	8	1.68	63.08	25

These data can be used to calculate system costs for a given application. For example, the high and low values of the total cost for an energy storage system with 500 kW peak power capability and 1 MWh storage capacity are summarized in Table 2.7 and presented in Fig. 2.8.

Table 2.7. Cost breakdown for an example system with 500 kW peak power and 1 MWh capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$220,000	$25,000	$2,520	$126,170	$25,000
Low value cost	$75,000	$4,000	$1,680	$63,080	$12,500



(a) **(b)**

Fig. 2.8. Cost share of the energy storage system with 500 kW peak power capability and 1 MWh storage capacity: high value cost (a) and low value cost percentages (b).

3. GENERAL ASSUMPTIONS FOR ANALYSIS OF BENEFITS IN APPLICATIONS

Some of the key assumptions made by Eyer and Corey[14] were used in this analysis to enable a useful comparison with previous benefit analyses.

Storage project life cycles of 5 and 10 years were assumed for life-cycle financial calculations. While previous work has limited the project life cycle to 10 years only, a 5-year life cycle was included here because the life of the used battery might by only 5 years. Although there is significantly more volatility in a shorter time frame, it could be necessary to deploy the technology for shorter time frames because technological advances could make some of the benefits derived from energy storage obsolete.

3.1 FIXED CHARGE RATE (DEPRECIATION OF EQUIPMENT)

The Eyer and Corey report referenced previously[14] used a fixed charge rate of 0.11 to estimate the annual avoided cost of equipment ownership; it has six elements—interest payments for bondholders, equity returns for stock owners, annual return of principal on depreciation, income taxes, property taxes, and insurance. This analysis also used a 0.11 fixed charge rate as a standard assumption.

3.2 PRESENT VALUE FACTORS

The present value (PV) of a future payment or a series of future payments reflects the time value of money. This is widely used in business and economics to enable comparisons of cash flows at different times. PV is generally calculated by using the formula $PV = C/(1 + i)^t$, where t is time and i is risk-free interest rate. Because there is no risk-free interest rate, U.S. Treasury rates are widely used for interest rates that are close to risk free. (Note: When U.S. Treasury rates are used, it becomes unnecessary to account for the inflation rate because inflation rates are built into Treasury rates.)

The average Treasury rates for 1971–2010 are given in Table 3.1. It should be noted that there is some volatility in the Treasury rates, especially the short-term rates.

Table 3.1. Average Treasury rates for 10-year notes

Year	Rate	Year	Rate	Year	Rate	Year	Rate
1971	6.16	1981	13.92	1991	7.86	2001	5.02
1972	6.21	1982	13.01	1992	7.01	2002	4.61
1973	6.85	1983	11.1	1993	5.87	2003	4.01
1974	7.56	1984	12.46	1994	7.09	2004	4.27
1975	7.99	1985	10.62	1995	6.57	2005	4.29
1976	7.61	1986	7.67	1996	6.44	2006	4.8
1977	7.42	1987	8.39	1997	6.35	2007	4.63
1978	8.41	1988	8.85	1998	5.26	2008	3.66
1979	9.43	1989	8.49	1999	5.65	2009	3.26
1980	11.43	1990	8.55	2000	6.03	2010	3.22

While it is quite well known that historical rates are not an indication of future rates, the historical rates provide an indication of possible fluctuations in rates. For this study, interest rates for the two most recent 10-year periods, 1991–2000 and 2001–2010, were used. The average interest rate for 10-year Treasury notes for 1991–2000 and 2001–2010 were 6.413 and 4.177, respectively. There are 20 periods in

10 years; thus, using the formula for PV noted previously, the PV factors have been calculated to be 7.3 and 8.11 for 1991–2000 and 2001–2010, respectively.

As mentioned previously, the short-term interest rates of Treasury notes are quite volatile: the average 5-year interest rates for 2005–2010 were 4.74, 4.45, 2.78, 2.22, and 1.91. The average of all these rates is 3.22, which translates into a PV factor of 4.62.

The PVs of the life-cycle benefits of the various grid applications discussed in this report are referred to as Life-Cycle Benefit I, II, III, or IV, defined as follows.

Life-Cycle Benefit I:	Assumes a life of 10 years and a discount rate of 4.18%
Life-Cycle Benefit II:	Assumes a life of 10 years and a discount rate of 6.41%
Life-Cycle Benefit III:	Assumes a life of 5 years and a discount rate of 3.22%
Life-Cycle Benefit IV:	Assumes a life of 10 years and a discount rate of 10% to enable comparison with reports in the literature[14]

4. ELECTRIC SUPPLY APPLICATIONS

4.1 ELECTRIC ENERGY TIME SHIFT

The annual benefit of electric energy time shifting for use of energy storage can be derived by assuming multiple electric energy purchase-sale transactions where the purchase is at a low price while sale is at a high price.

A chronological hourly price forecast for California for 2009 is shown in Fig. 4.1. Based on these data, there are about 900 hours per year when price is above \$100/MWh (10¢/kWh). During off-peak, the price is about \$50/MWh to \$60/MWh (5¢/kWh to 6¢/kWh).

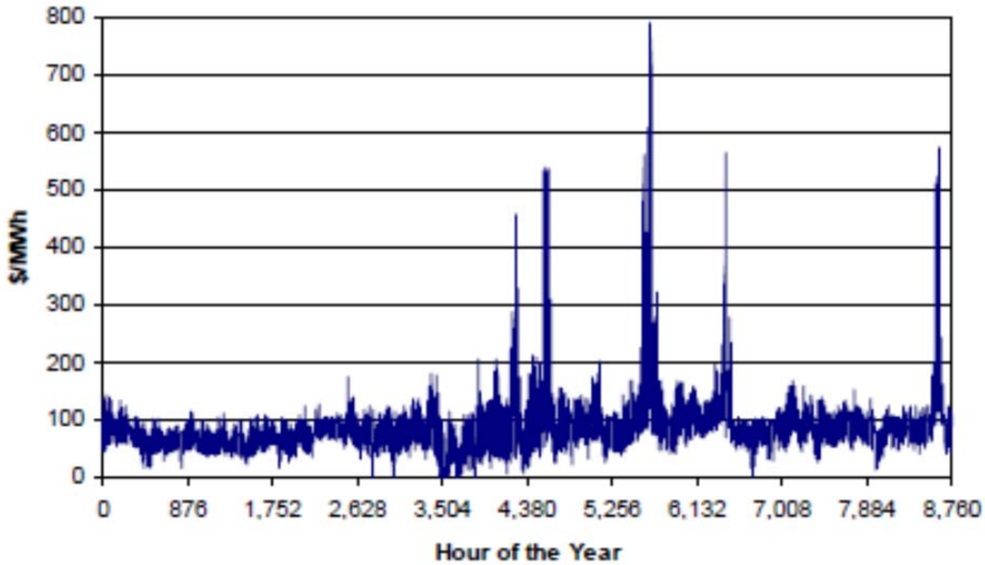


Fig. 4.1. Chronological hourly price data for California for 2009.

The transaction decision can then be based on the difference between storage system cost (cost of wear + cost of charging the system + storage losses) and the value of the benefit.

It is important to note that this benefit needs to be revisited if there is any substantial deployment of PHEVs and EVs because the current off-peak hours will see spikes due to increased demand for charging these vehicles during off-peak hours.

The annual time-shift benefit is shown in Fig. 4.2. The data for this figure have been taken from the literature.[13] The plots show a variable operating cost (VOC) of 1¢/kWh$_{out}$, and the net benefits are for storage efficiencies ranging from 70% to 90% for storage whose discharge duration ranges from 1 hour to 8 hours.

The PV of 5- or 10-year life cycles can be estimated by multiplying the annual value from the plot with the discount rates indicated in Sect. 4.2. Table 4.1 shows the time-shift application benefit for various storage efficiencies.

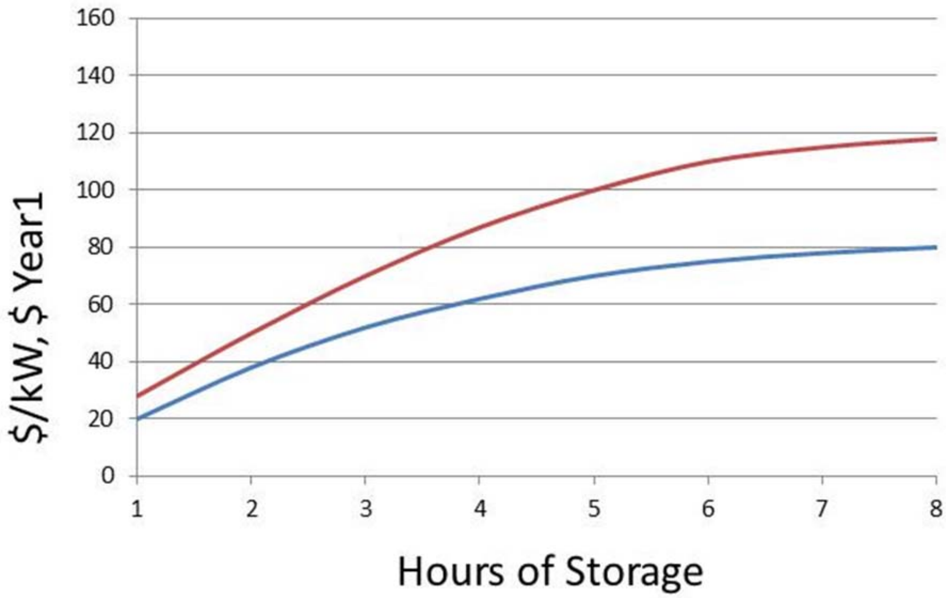


Fig. 4.2. Annual energy time-shift benefit.

Table 4.1. Life-cycle present value of energy time-shift application

Benefit category	**Storage efficiency 0.7**	**Storage efficiency 0.8**	**Storage efficiency 0.9**
Life-Cycle Benefit I ($)	541.41	626.77	712.12
Life-Cycle Benefit II ($)	487.34	564.17	640.99
Life-Cycle Benefit III ($)	308.64	357.30	405.96
Life-Cycle Benefit IV ($)	478.70	554.16	629.63

Electric energy time-shift application requires a minimum of at least 1 MW power per ISO transaction. It should be noted that energy storage systems with smaller power ratings can be aggregated. The highest peak power of this application can be 500 MW. The storage capacity depends on the discharge duration, which is typically from 2 to 8 hours.[23] The discharge duration depends on the energy price differential, storage efficiency, and storage VOCs. A storage system with 1 MW peak power rating and 5 MWh storage capacity (5 hours) was used for the cost calculations. Therefore, the cost of the system depending on the size of the storage can be calculated as in Table 4.2. It should be noted that although power rating may vary from 1 to 500 MW and discharge duration may vary between 2 and 8 hours, the selected power rating and storage capacity levels are reasonable values for an application employing used batteries.

Figure 4.3 represents the total cost and the cost share component of these electric energy time-shift applications.

Table 4.2. Cost of electric energy time-shift application with 1 MW peak power and 5 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$1,100,000	$50,000	$12,600	$630,850	$50,000
Low value cost	$375,000	$8,000	$8,400	$315,400	$25,000

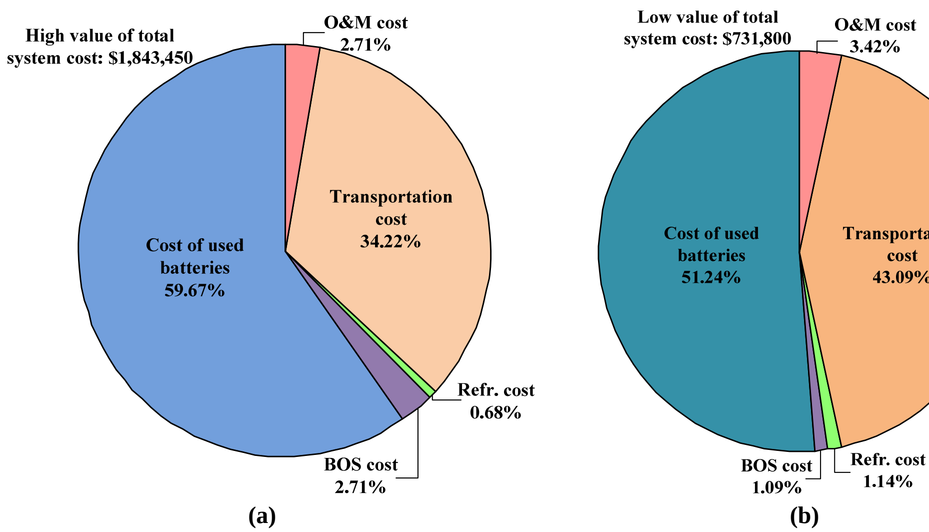


Fig. 4.3. Cost breakdowns for high (a) and low (b) values of the electric energy time-shift application.

4.2 ELECTRIC SUPPLY CAPACITY

While sharp permanent increases in demand require utility companies to permanently add capacity, additional capacity is not necessarily the solution to small increases in demand. Because of this, some utility companies rent generation capacity in the wholesale market. Energy storage alternatives can be used in lieu of adding or renting additional capacity. The financial value of the benefit can be estimated by using either of two options (i.e., adding or renting capacity).

The assumptions for these estimates are as follows.

- Plant is a "new generation" clean efficient natural gas fired combustion turbine-based power plant that operates from 2,000 to 6,000 hours.
- Generic installed cost is $1,000/kW.
- O&M cost is $10/kW per year.

Estimate. The utility fixed charge rate of 0.11 gives an annual cost of ownership of $110/kW-year ($1,000/kW × 0.11 = $110/kW-year). The ownership cost and O&M cost give total cost of $120/kW-year. Table 4.3 shows the results for the various life-cycle benefit scenarios.

Table 4.3. Life-cycle present value of electric supply capacity application

Life-Cycle Benefit I	$973.20
Life-Cycle Benefit II	$876.00
Life-Cycle Benefit III	$554.80
Life-Cycle Benefit IV	$860.47

Several of the organized electricity markets in the United States [the New York Independent System Operator (NYISO), ISO New England, PJM Interconnection] have capacity markets with periodic auctions that produce a price signal as to the marginal cost of capacity in their systems. The California ISO (CAISO) does not have a capacity market but has a capacity procurement mechanism in which a reference fixed charge of $55/kW-year is paid to each supplier contracted to provide capacity under this mechanism in 2010.

The value that would accrue to refurbished batteries used in capacity markets would be highly dependent on location. Spot procurement auctions in NYISO's Installed Capacity market for the summer-2010 capability period ranged from $12.90/kW-month for New York City to $2.47/kW-month for the rest of the system. Where a capacity market does not exist to provide explicit price signals, the value of battery storage used in this application must be estimated looking at the cost of the alternative (typically a combined cycle gas turbine).

The electric supply capacity application requires the same peak power range as that of the electric energy time-shift application. However, the storage capacity requirement is between 4 and 6 hours.[14] The discharge duration depends on the energy price differential, storage efficiency, and storage VOCs. For the cost calculations, a storage system with 1 MW peak power rating and 4 MWh storage capacity (4 hours) was selected. Therefore, the cost of the system depending on the size of the storage can be calculated as in Table 4.4. It should be noted that although power rating may vary from 1 to 500 MW and discharge duration may vary between 4 and 6 hours, the selected power rating and storage capacity levels are reasonable values for an application employing used batteries.

Figure 4.4 represents the total cost and the cost share components of the electric supply capacity application.

Table 4.4. Cost of electric supply capacity application with 1 MW peak power and 4 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$880,000	$50,000	$10,800	$504,680	$50,000
Low value cost	$300,000	$8,000	$6,720	$252,320	$25,000

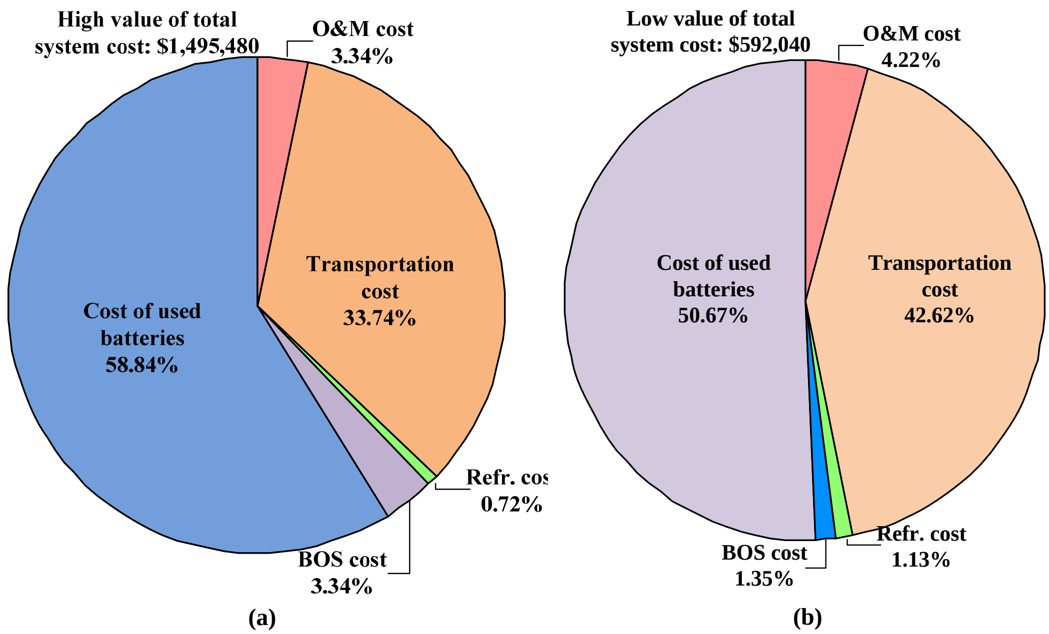


Fig. 4.4. Cost breakdowns for high (a) and low (b) values of the electric supply capacity application.

5. ANCILLARY SERVICE APPLICATIONS

5.1 LOAD FOLLOWING

The marginal cost of generation is primarily fuel and maintenance. This cost can be avoided or reduced if energy storage is used instead of generation to provide load-following service. The capacity-related cost (i.e., cost incurred to add generation capacity) depends on the need, which can vary depending on the region and the time of year. Additional generation capacity could be from hydroelectric to combined cycle generation capacity

At the low end, the load-following benefit can be estimated based on the marginal cost of low-cost hydroelectric generation, and the high end marginal cost can be based on combined cycle generation marginal cost. The assumptions for these generation methods for this study are $20/MW and $50/MW for low- and high-end marginal cost of generation, respectively.

The capacity-related benefit is estimated by assuming generation capacity cost of $60/kW at the low end to own or rent simple cycle combustion turbines and $120/kW at the high end.

Table 5.1 summarizes life-cycle cost calculations for service and capacity related costs. A mid-range marginal cost of $35/MWh was also included for service-related costs.

Table 5.1. Life-cycle present value of load following application (energy and capacity components)

Avoided cost	Annual benefit ($/kW-year)	Life-Cycle Benefit I ($)	Life-Cycle Benefit II ($)	Life-Cycle Benefit III ($)	Life-Cycle Benefit IV ($)
		Energy component—500 hours			
$20/MWh	10.0	81.1	73.0	46.2	71.7
$35/MWh	17.5	141.9	127.8	80.9	125.5
$50/MWh	25.0	202.8	182.5	115.6	179.3
		Energy component—1,000 hours			
$20/MWh	20.0	162.2	146.0	92.5	143.4
$35/MWh	35.0	283.9	255.5	161.8	251.0
$50/MWh	50.0	405.5	365.0	231.2	358.5
		Energy component—2,000 hours			
$20/MWh	40.0	324.4	292.0	184.9	286.8
$35/MWh	70.0	567.7	511.0	323.6	501.9
$50/MWh	100.0	811.0	730.0	462.3	717.1
		Capacity component			
$60/MW	60.0	486.6	438.0	277.4	430.2
$120/MW	120.0	973.2	876.0	554.8	860.5

The load-following application requires the same peak power range as that of the electric energy time-shift application and the electric supply capacity application (1 to 500 MW). However, the storage capacity requirement is between 2 and 4 hours as 1-hour discharge duration provides 2 hours of load following.[14] For the cost calculations, a storage system with 1 MW peak power rating and 3 MWh storage capacity (3 hours) was considered. Therefore, the cost of the system depending on the size of the storage can be calculated as in Table 5.2. It should be noted that although power rating may vary from 1 to

500 MW and discharge duration may vary between 2 and 4 hours, the selected power rating and storage capacity levels are reasonable values for an application employing used batteries.

Table 5.2. Cost of electric supply capacity application with 1 MW peak power and 3 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$660,000	$50,000	$7,560	$378,510	$50,000
Low value cost	$225,000	$8,000	$5,040	$189,240	$25,000

Figure 5.1 presents the total cost and the cost share components of the load following application.

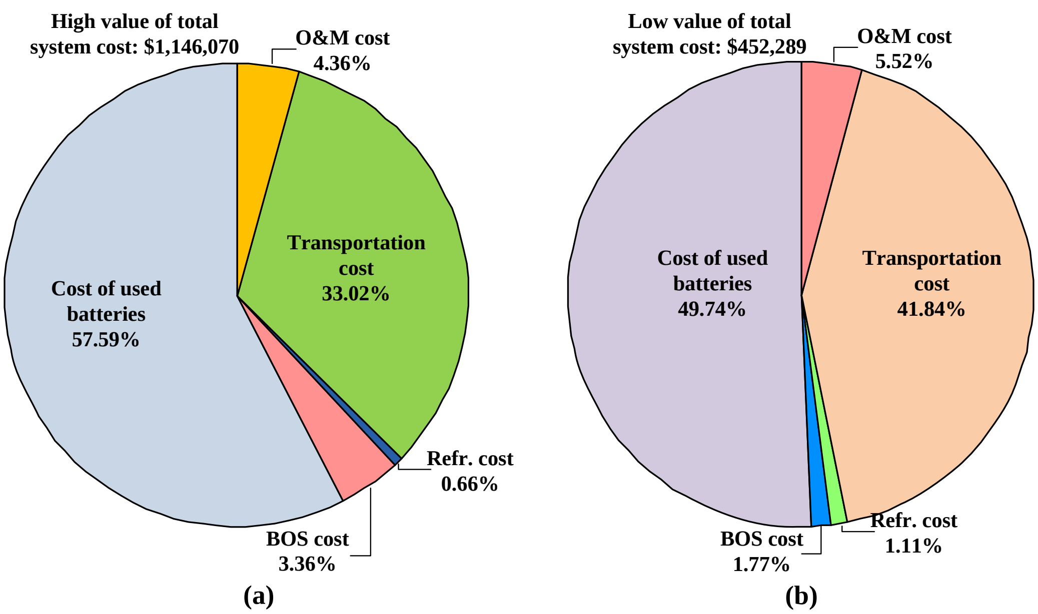


Fig. 5.1. Cost breakdowns for high (a) and low (b) values of the load-following application.

5.2 AREA REGULATION

For the calculation of the energy storage benefits of area regulation, the storage benefit will be the same as conventional generation-based regulation and reflect the prevailing price for the service in dollars per megawatt. Unlike generation used for area regulation, efficient storage can provide 2 kW for each 1 kW of rated output because it can provide for regulation while charging and discharging.

Eyer and Corey estimated revenue for providing up and down regulation services for 1 year based on CAISO's published hourly process for 2006.[14] This was the method followed here as well. In 2006, the combined price for up and down regulations averaged $36.7/MW per service hour based on an annual average of $21.48/MW per service hour for up regulation and $15.33/MW per service hour for down regulation. After escalating for 2 years at 2.5%, the price assumed was an average of $38.55/MW per service hour.

For operation during 50% and 80% of the year, the life-cycle values for selected discount rates and operating life periods are shown in Table 5.3.

Table 5.3. Life-cycle present value of regulation application

	Low		High	
Capacity factor	0.5		0.8	
Annual service hours	4380	7008	4380	7008
Regulation price ($/MW)	25	40	25	40
Annual benefits ($/kW)	109.2	175.2	175.2	280.32
Life-Cycle Benefit I ($)	888.05	1,420.87	1,420.87	2,273.40
Life-Cycle Benefit II ($)	799.35	1,278.96	1,278.96	2,046.336
Life-Cycle Benefit III ($)	506.25	810.00	810.00	1,296.00
Life-Cycle Benefit IV ($)	785.18	1,256.28	1,256.28	2,010.05

The power rating of the area regulation application ranges from 1 MW to 40 MW. The lower power rating is based on the per ISO transaction minimum whereas the higher is based on 50% of the estimated CA technical potential of 80 MW.[14] The peak power rating of the storage system is considered to be 20 MW for the cost calculations. Based on the Beacon Power Corporation flywheel area regulation demonstration, the required discharge duration varies between 15 and 30 minutes, which results in 5 MWh to 10 MWh storage capacity. For the cost calculations of this application, storage capacity is considered as 5 MWh (15-minute regulation duration). The storage capacity is typically lower than the peak power capability in regulation applications. This is because an upward regulation (regulation as a generator) is followed by a regulation downward (regulation as a load, recharging). Thus, the regulation can be provided in a charge sustaining manner, avoiding larger storage size requirements. The cost of the system depending on the size of the storage for this application can be calculated as in Table 5.4.

Table 5.4. Cost of area regulation application with 20 MW peak power and 5 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$1,100,000	$1,000,000	$12,600	$630,850	$1,000,000
Low value cost	$375,000	$160,000	$8,400	$315,400	$50,000

Figure 5.2 presents the total cost and the cost share components of the area regulation application.

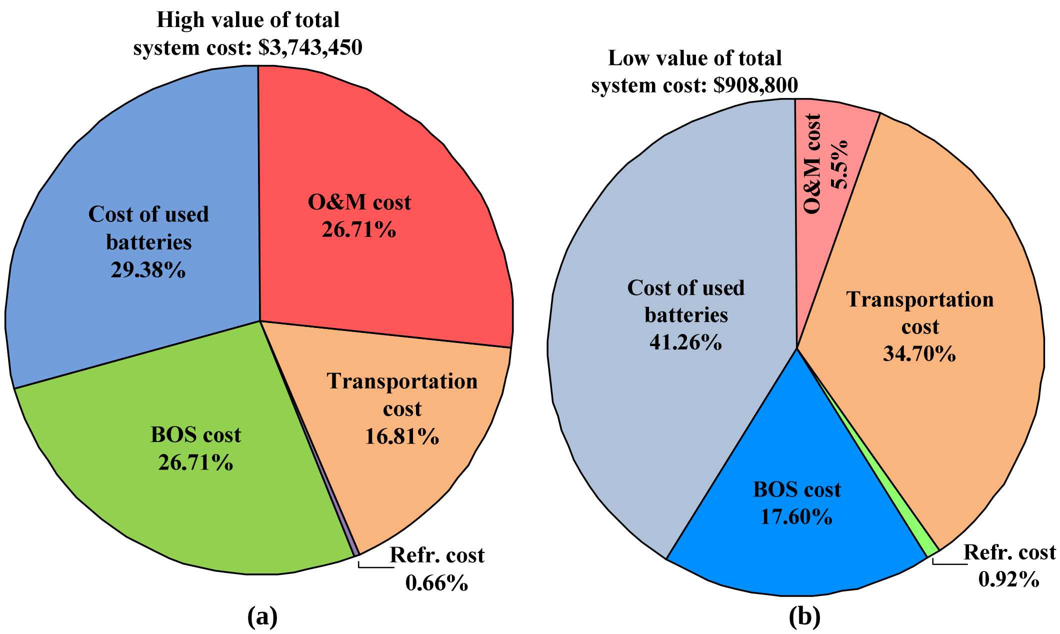


Fig. 5.2. Cost breakdowns for high (a) and low (b) values of the area regulation application.

5.3 ELECTRIC SUPPLY RESERVE CAPACITY

The electric supply reserve capacity benefit is somewhat small because generation-based reserves are inexpensive. The estimate of benefit is based on the price paid for reserves and the number of hours per year during which storage provides reserves.

The price paid for reserve capacity is assumed to be $3/MW and $6/MW for low and high end, respectively. The storage is assumed to provide 2,628 and 5,256 service hours per year at low and high end, respectively.

The resulting benefits are shown in Table 5.5 for both scenarios using various discount rates.

Table 5.5. Life-cycle present value of electric supply reserve application

	Low	High
Capacity factor	0.3	0.6
Annual service hours	2,628	5,256
Charge ($/MW per service hour)	3.00	6.00
Annual benefits ($/kW)	7.88	31.54
Life-Cycle Benefit I ($)	63.94	255.76
Life-Cycle Benefit II ($)	57.55	230.21
Life-Cycle Benefit III ($)	36.45	145.80
Life-Cycle Benefit IV ($)	56.53	226.13

The power rating of this application may vary from 1 MW to 500 MW. The low value is based on the per ISO transaction minimum whereas the high value is based on the combined cycle generators providing similar service. This application typically allows time for generation-based reserves to come online and may help the black start of other types of generators/storage systems. Therefore, its required capacity is relatively lower and generally 1 to 2 hours of discharge duration would suffice. For the cost calculations for this application, the power rating was considered to be 50 MW and the storage capacity 50 MWh (1 hour). The cost of the system depending on the size of the storage for this application can be calculated as in Table 5.6.

Table 5.6. Cost of electric supply reserve capacity application with 50 MW peak power and 50 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$11,000,000	$2,500,000	$126,000	$6,308,500	$2,500,000
Low value cost	$3,750,000	$400,000	$84,000	$3,154,000	$1,250,000

Figure 5.3 presents the total cost and the cost share components of the electric supply reserve capacity application.

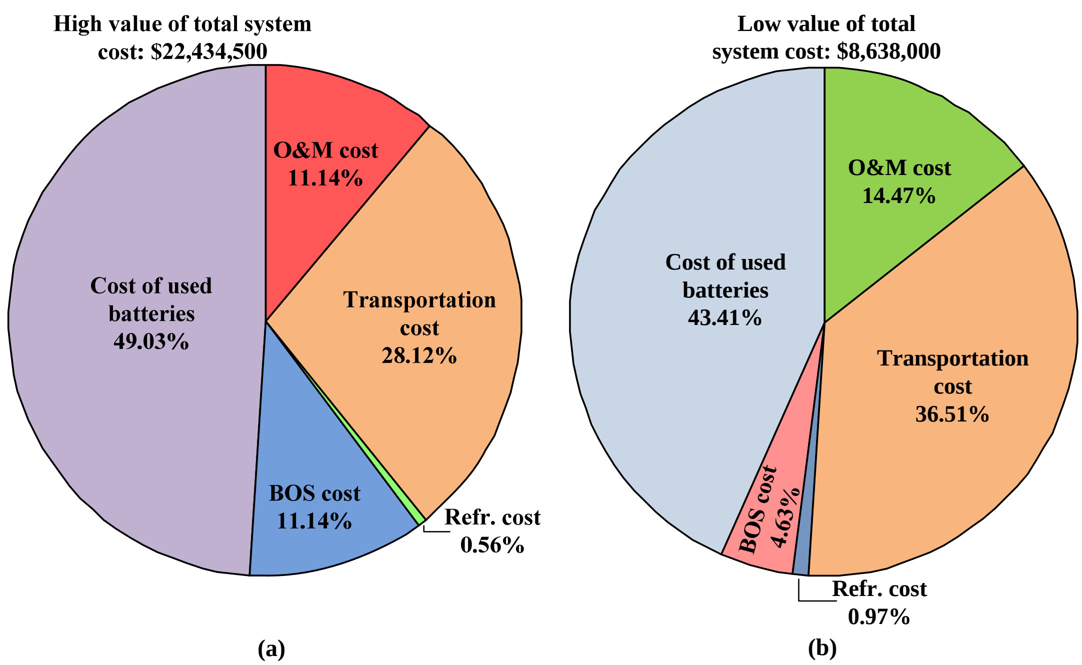


Fig. 5.3. Cost breakdowns for high (a) and low (b) values of the electric supply reserve capacity application.

5.4 VOLTAGE SUPPORT

In voltage support, the time value of money is not involved. We assume one or two outages over a 10-year period.

For an outage lasting 1 hour, the estimated value is $20 per hour of unserved load (i.e., $20/kW life cycle for each kilowatt of system peak load).[14]

Market potential is based on the premise that combined voltage support resources are distributed, are located where they can provide good support, and have an aggregate rating equal to 5% of peak load.

- To avoid 1-hour outage, the benefit is $\$20/kW_{load}/0.05 = \$400/kW$ of distributed storage.
- To avoid 2-hour outage, the benefit is $\$40/kW_{load}/0.05 = \$800/kW$ of distributed storage.

The voltage-support application power rating may vary from 1 MW to 10 MW, assuming the distributed deployment to locally serve the voltage support.[14] The required time durations for voltage support may vary from 15 minutes to 1 hour considering the time needed for system stabilization and orderly load shedding. For the cost calculations for the voltage-support application, a power rating of 1 MW and 30 minutes of discharge duration (500 kWh storage capacity) were considered. The cost of the system depending on the size of the storage for this application can be calculated as in Table 5.7.

Table 5.7. Cost of voltage support application with 1 MW peak power and 500 kWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$110,000	$50,000	$1,260	$63,085	$50,000
Low value cost	$37,500	$8,000	$840	$31,540	$25,000

Figure 5.4 presents the total cost and the cost share components of the voltage support application.

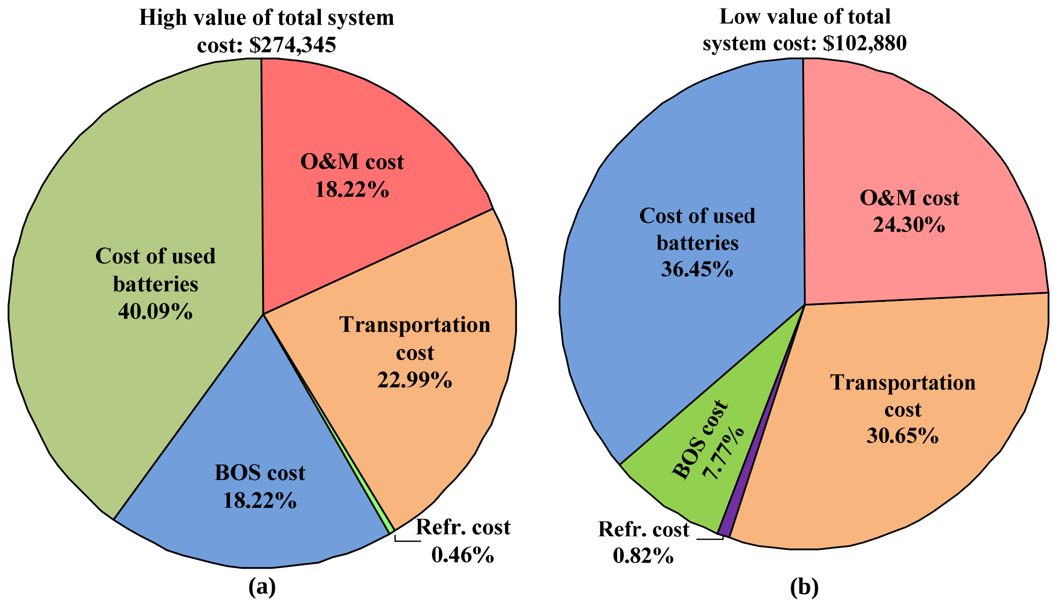


Fig. 5.4. Cost breakdowns for high (a) and low (b) values of the voltage support application.

6. GRID SYSTEM APPLICATIONS

6.1 TRANSMISSION SUPPORT

Energy storage can complement the load carrying capacity of transmission systems, avoid transmission outages, and defer the need to add transmission capacity [purchase of additional transmission and distribution (T&D) equipment and/or rent to participate in wholesale electric marketplace].

The estimated benefit is the cost of the most likely alternative if storage was not deployed. For example, if capacitors are proposed as the standard solution, then the energy storage offset is the cost of capacitors. The financial benefit values in Table 6.1 were estimated from the literature.[14,16] All values are for southern California, and cost is $12.8/kW per occurrence. Furthermore, it was assumed that there would be three occurrences per year.

Table 6.1. Life-cycle present value of transmission support application

Benefit type	Annual benefit ($/kW-year)	Life-Cycle Benefit I	Life-Cycle Benefit II	Life-Cycle Benefit III	Life-Cycle Benefit IV
Transmission enhancement	15.1	122.46	110.23	69.81	108.28
Voltage control ($ capital)	NA	29	29	29	29
Subsynchronous resonance ($ capital)	NA	16	16	16	16
Damping underfrequency shedding (per occurrence)	38.4	38.4	38.4	38.4	38.4
Total	53.5	205.86	193.63	153.21	191.68

The peak power requirement for transmission support ranges from 10 MW to 100 MW. The lower power rating is typically for sub-transmission applications.[14] This study considered 50 MW peak power capability a reasonable level for transmission support. The discharge duration is between 2 and 5 seconds according to Eyer and Corey.[14] However, Nourai et al. indicate that the battery should be sized to handle a 1-hour duration for transmission support applications.[28] In fact, for short-term transmission system performance improvements, a discharge duration on the order of seconds is reasonable. However, having a relatively larger storage capacity would improve long-term performance by providing a synergistic benefit for other transmission level applications such as congestion relief and upgrade deferral. Therefore, in this study 20 minutes of discharge duration was used, which results in 16.67 MWh of storage capacity. The cost of the system depending on the size of the storage for this application can be calculated as in Table 6.2.

Figure 6.1 presents the total cost and the cost share components of the transmission-support application.

Table 6.2. Cost of transmission-support application with 50 MW peak power and 16.67 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportatio n cost	Operation and maintenance cost
High value cost	$3,667,400	$2,500,000	$42,008.4	$2,103,253.9	$2,500,000
Low value cost	$1,250,250	$400,000	$28,005.6	$777,988.9	$1,250,000

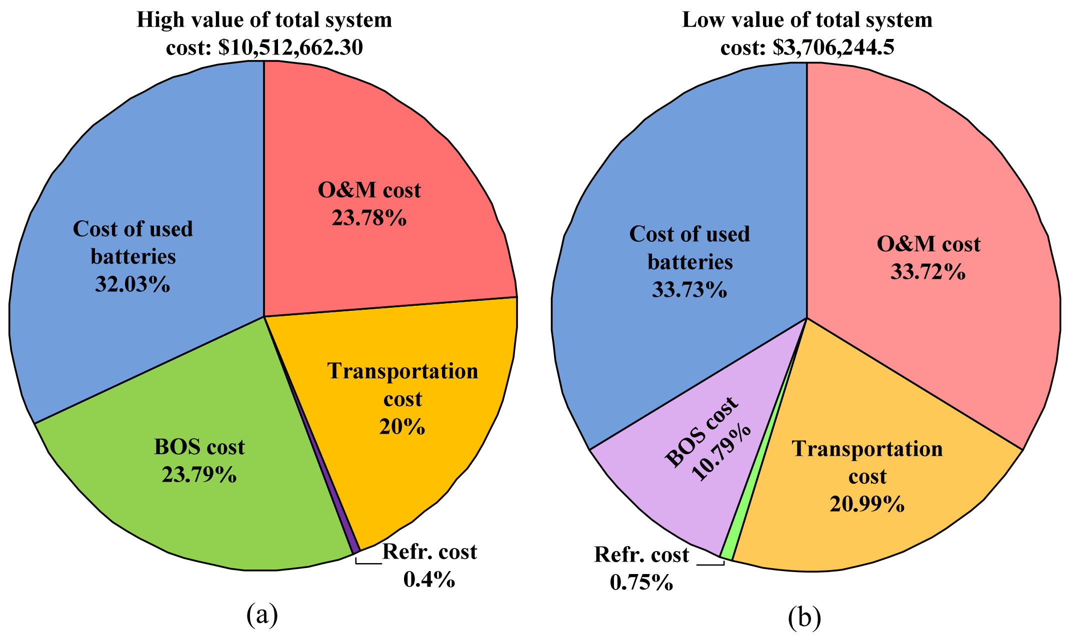


Fig. 6.1. Cost breakdowns for high (a) and low (b) values of the transmission-support application.

6.2 TRANSMISSION CONGESTION RELIEF

The alternatives to energy storage for transmission congestion relief are as follows.

- Dumping energy upstream of congestion
- Load management and energy efficiency downstream of congestion
- Congestion charges
- Adding transmission capacity

If we assume that most of the new congestion will probably occur due to renewables deployment, it is safe to assume that dumping energy or doing nothing will not be options.

In parts of California, congestion is present for 10%–17% of all hours during the year, and congestion charges range from $5/MW per service hour to about $15/MW per service hour.

The resulting benefits are shown in Table 6.3 for both scenarios using various discount rates.

Table 6.3. Life-cycle present value of transmission-congestion-relief application

	Low	High
Portion of year	0.10	0.15
Hours of year	876	1314
Transmission Access Charge ($/MW per hour of service)	5	15
Annual benefits ($/kW)	4.38	19.71
Life-Cycle Benefit I	35.52	159.85
Life-Cycle Benefit II	31.97	143.88
Life-Cycle Benefit III	20.25	91.13
Life-Cycle Benefit IV	31.41	141.33

The power rating for the transmission-congestion-relief application varies from 1 MW to 100 MW,[14] depending on the severity of the congestion. Based on the work in transmission congestion management by Wibowo et al. and Raja et al.,[29,30] 20 MW peak power was selected for transmission congestion relief. The discharge duration for this application may vary from 3 to 6 hours based on the peak demand hours as congestion typically occurs in peak demand hours. Therefore, 4 hours of discharge capability would be reasonable for relieving the congestion, which results in 80 MWh total energy capacity. The cost of the system depending on the size of the storage for this application can be calculated as in Table 6.4.

Table 6.4. Cost of transmission-support application with 20 MW peak power and 80 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$17,600,000	$1,000,000	$201,600	$10,093,600	$1,000,000
Low value cost	$6,000,000	$160,000	$134,400	$5,046,400	$500,000

Figure 6.2 presents the total cost and the cost share components of the transmission-congestion-relief application.

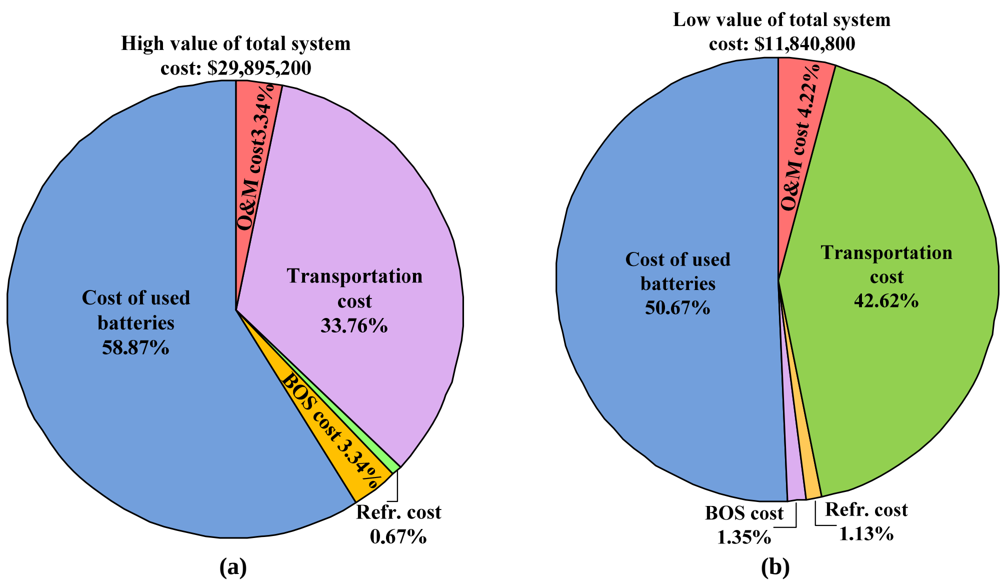


Fig. 6.2. Cost breakdowns for high (a) and low (b) values of the transmission-congestion-relief application.

6.3 TRANSMISSION AND DISTRIBUTION UPGRADE DEFERRAL

The T&D upgrade deferral benefit is essentially the financial savings for deferring the purchase of the equipment. The savings include the cost of financing, taxes, and insurance and can be calculated by simply multiplying the total cost by the charge rate of 0.11.

In California, the marginal cost is roughly $420/kW for an upgrade in any given year for most locations (Table 6.5) and $662/kW for expensive locations (Table 6.6).[14] The upgrade factor is added capacity divided by existing capacity. The values in Tables 6.5 and 6.6 are $684/kVA of storage for 1 year and reflect a 0.33 T&D upgrade factor, 0.11 fixed charge rate, and 3% storage power.

Table 6.7 summarizes the life-cycle benefit calculations for the T&D upgrade deferral application.

Table 6.5. Transmission and distribution upgrade cost and benefits for low marginal cost ($420/kW)

Upgrade scenario final rating (MVA)	Capacity added (MVA)	Upgrade factor	Upgrade installed cost[a] ($/kVA[b])	Upgrade installed cost[a] ($)	Upgrade annual cost[c] ($)	Storage 1 year benefit[d] ($/kVA-year)
15	3	0.25	105.0	1,575.000	173,250	481
16	4	0.33	140.0	2,240.000	246,400	684
18	6	0.50	210.0	3,780,000	415,800	1,155

[a]If marginal cost per kVA of T&D capacity $/kVA added is $420/kVA.
[b]Per kVA *installed.*
[c]$Upgrade installed cost * 0.110 fixed charge rate.
[d]$Upgrade annual cost ÷ 360 kVA (based on 3.0% storage power).

Table 6.6. Transmission and distribution upgrade cost and benefits for high marginal cost ($662/kW)

Upgrade scenario final rating (MVA)	Capacity added (MVA)	Upgrade factor	Upgrade installed cost[a] ($/kVA[b])	Upgrade installed cost[a] ($)	Upgrade annual cost[c] ($)	Storage 1 year benefit[d] ($/kVA-year)
15	3	0.25	165.5	2,482.500	273,075	759
16	4	0.33	220.7	3,530.667	388,373	1,079
18	6	0.50	331.0	5,958,000	655,380	1,821

[a]If marginal cost per kVA of T&D capacity $/kVA added is $662/kVA.
[b]Per kVA *installed.*
[c]$Upgrade installed cost * 0.110 fixed charge rate.
[d]$Upgrade annual cost ÷ 360 kVA (based on 3.0% storage power).

Table 6.7. Life-cycle present value of transmission and distribution upgrade deferral application

Upgrade Scenario final rating (MVA)	Annual benefits ($/kW)	Life-Cycle Benefit I	Life-Cycle Benefit II	Life-Cycle Benefit III	Life-Cycle Benefit IV
		High marginal cost ($662/kW)			
15	481	3900.91	3511.30	2223.80	3449.03
16	855	6934.05	6241.50	3952.92	6130.82
18	1155	9367.05	8431.50	5339.90	8281.98
		Low marginal cost ($420/kW)			
15	759	6155.49	5540.70	3509.08	5442.45
16	1348.75	10938.36	9845.87	6235.67	9671.28
18	2276.25	18460.39	16616.63	10523.77	16321.96

The power rating of this application can be as low as 250 kW (the smallest likely)[14] and as high as 5 MW, which is the high end for distribution and subtransmission.[14] In 2006, American Electric Power installed a 1 MW energy storage system in North Charleston, West Virginia, for upgrade deferral.[31,32] Therefore, this study considers a 1 MW system, too. Because the T&D line capacities are highly used during peak demand hours, discharge duration is determined by the peak hours. For this study, 4 hours of discharge duration were used, which results in 4 MWh storage capacity. Table 6.8 shows the cost breakdown of upgrade deferral applications.

Table 6.8. Cost of transmission and distribution upgrade deferral with 1 MW peak power and 4 MWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$880,000	$50,000	$10,080	$504,680	$50,000
Low value cost	$300,000	$8,000	$6,720	$252,320	$25,000

Figure 6.3 presents the total cost and the cost share components of the T&D upgrade deferral application.

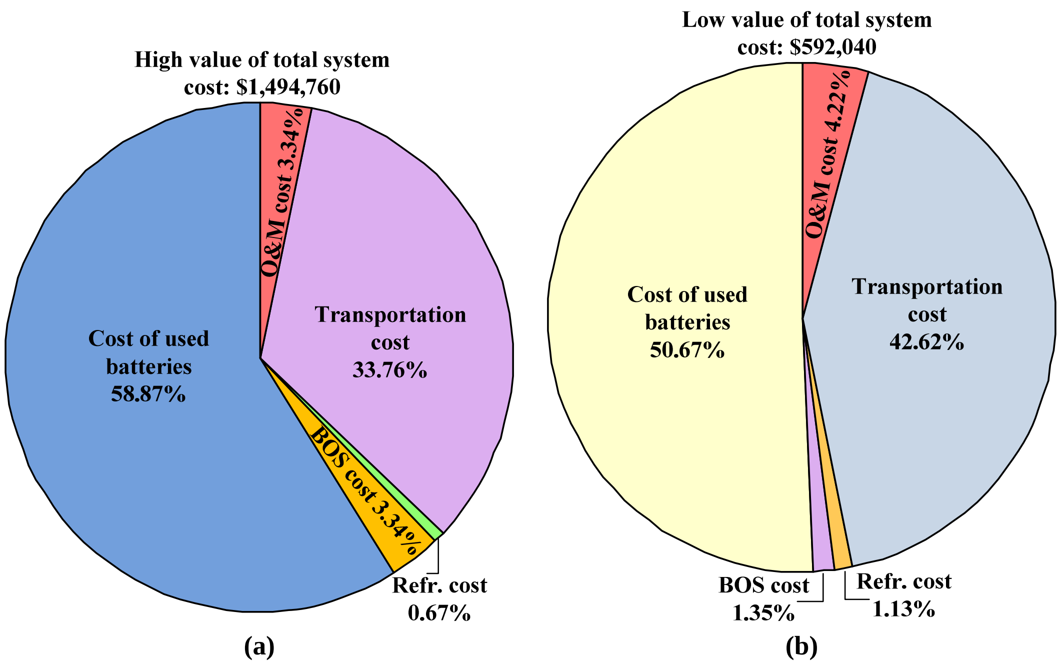


Fig. 6.3. Cost breakdowns for high (a) and low (b) values of the transmission and distribution upgrade deferral application.

6.4 SUBSTATION ON-SITE POWER

Energy storage (lead-acid batteries) provides power at electric utility substations for switching components and for substation communications and control equipment when the grid is not energized. The benefit value is estimated based on the price of a high quality uninterruptible power supply (UPS) system.[14] The cost of a state-of-the-art lead-acid-battery-based system with 8-hour discharge duration is based on a price of $225/kW for power and $200/kWh of discharge. The system price for an 8-hour system is $1,825/kW [$225/kW + (8 hours × $200/kWh)] and for a 16-hour, $3,425/kW. In this calculation, the variable costs have been ignored for such a system.

The batteries used in substations are required to provide the backup power for substation protection and control devices (relays, reclosers, switchgears, etc.) when grid power is not available. The peak power requirement usually depends on the substation size and number of protection and control devices. Based on an EPRI substation on-site power survey, the peak power requirement may vary from 1.5 kW to 5 kW.[33] Robinson et al.[34] and Dewar[35] indicate that a steady-state standby current in a typical 132 kV substation is 40 A for 6 hours in 110 V_{dc} voltage. Therefore, for this application, $110V_{dc} \times 40$ A = 4.4 kW would be required. The energy storage capacity for substation on-site power depends on the outage duration as the batteries supply the protection and control equipment only in outage hours. Therefore, the discharge duration may vary from minutes to hours. To provide safe operation during long outages (e.g., 6 hours), a reasonable storage capacity would be 26.4 kWh. Table 6.9 shows the cost breakdowns for substation on-site power applications.

Table 6.9. Cost of substation on-site power application with 4.4 kW peak power and 26.4 kWh storage capacity

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$5,808	$220	$66.53	$3,336.96	$220
Low value cost	$1,980	$35.2	$44.35	$1,665.31	$110

Figure 6.4 presents the total cost and the cost share components of the substation on-site power application.

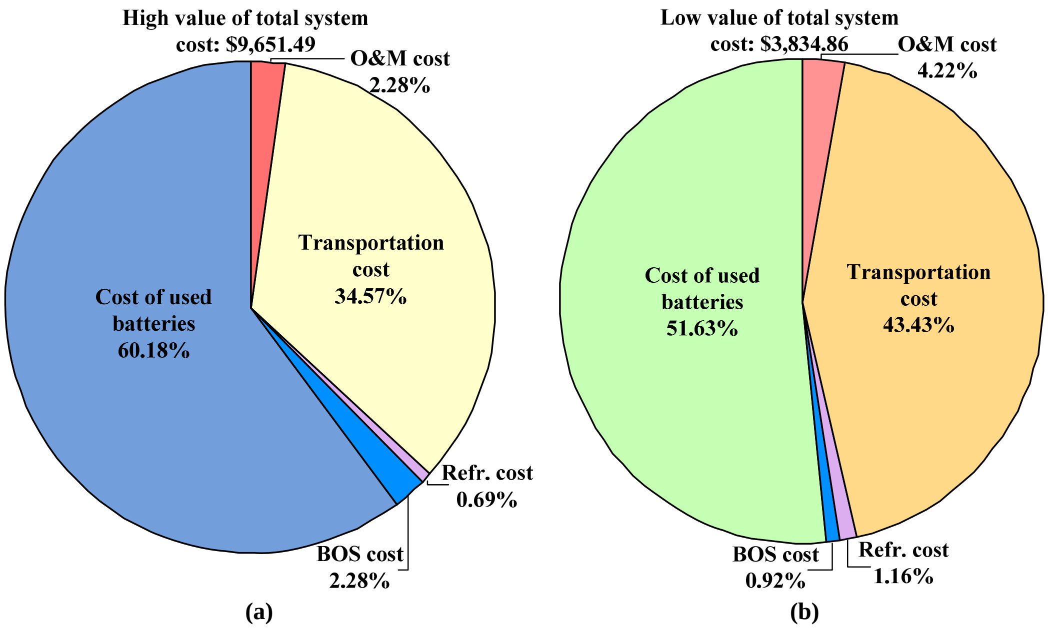


Fig. 6.4. Cost breakdowns for high (a) and low (b) values of the substation on-site power application.

7. CUSTOMER APPLICATIONS

7.1 TIME-OF-USE ENERGY COST MANAGEMENT

Time-of-use (TOU) energy cost management is based on taking advantage of fluctuations in the price and use of energy. Energy storage is effective in this application if charging is done when the price of energy is low and the energy is used when the price is high. For convenience, the standard assumption values for this section of the report are calculated from PG&E's A-6 small general TOU service tariff (http://www.pge.com/tariffs), which is applicable if the power requirements are in the 199 kW–500 kW range. The summer billing period extends from May through October, and the rest of the months are in the winter billing period. Summer peak hours are 12:00–6:00 pm (Monday–Friday, except holidays); off-peak hours are 9:30 pm–8:30 am, Monday–Friday and all day Saturday, Sunday, and holidays. There are no winter peak hours, but partial peak hours are 8:30 am–9:30 pm (Monday–Friday, except holidays); off-peak hours are 9:30 pm–8:30 am, Monday–Friday and all day Saturday, Sunday, and holidays. Table 7.1 is an example of TOU energy cost tariffs.

Table 7.1. Time-of-use energy cost tariff example

Period	Total ($)	Generation ($)	%	Distribution ($)	%
Peak summer	0.37	0.21	57.0	0.13	34.9
Partial-peak summer	0.17	0.09	53.0	0.05	29.8
Off-peak summer	0.11	0.06	49.9	0.03	23.3
Partial-peak winter	0.13	0.06	46.0	0.04	31.8
Off-peak winter	0.11	0.05	47.4	0.03	25.7

Transmission: $0.00913 for all hours.

Using the prices in Table 7.1, savings from energy storage would be calculated according to the following.

- The A-6 tariff on-peak energy price applies to 720 hours/year. Storage with 6-hour discharge would allow the end user to avoid annual on-peak charges of $266/kW-year [0.37/kWh × 720 hours/year].
- For an 80% efficient system, it is necessary to use 1.25 kWh of energy to get 1 kWh. The charging cost using the off-peak energy price is $99/kW-year [$0.11/kWh × (720 × 1.25) hours/year].
- The cost reduction is $167/kW-year.

Table 7.2 shows life-cycle benefits based on this "formula."

Table 7.2. Life-cycle present value of time-of-use energy cost application

Benefit category	Benefits ($/kW)
Annual benefits	167.40
Life-Cycle Benefit I	1,357.61
Life-Cycle Benefit II	1,222.02
Life-Cycle Benefit III	773.94
Life-Cycle Benefit IV	1,200.35

This application is available to both residential and commercial/industrial users for avoiding high price energy purchases during peak demand hours. The typical power rating for a residential application can be 0.5 kW to 1 kW, and the discharge duration can be 3–6 hours depending on the peak demand hours.[14] Therefore, this study used 1 kW peak power capability with 4 kWh of energy storage capacity for residential application calculations. Table 7.3 shows the cost breakdown for TOU energy cost management for a residential application, and Fig. 7.1 shows the total cost and cost share components of TOU energy cost management for residential applications.

Table 7.3. Cost of time-of-use energy cost management application based on 1 kW peak power and 4 kWh storage capacity (residential users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$880	$50	$10.08	$504.68	$50
Low value cost	$300	$8	$6.72	$252.32	$25

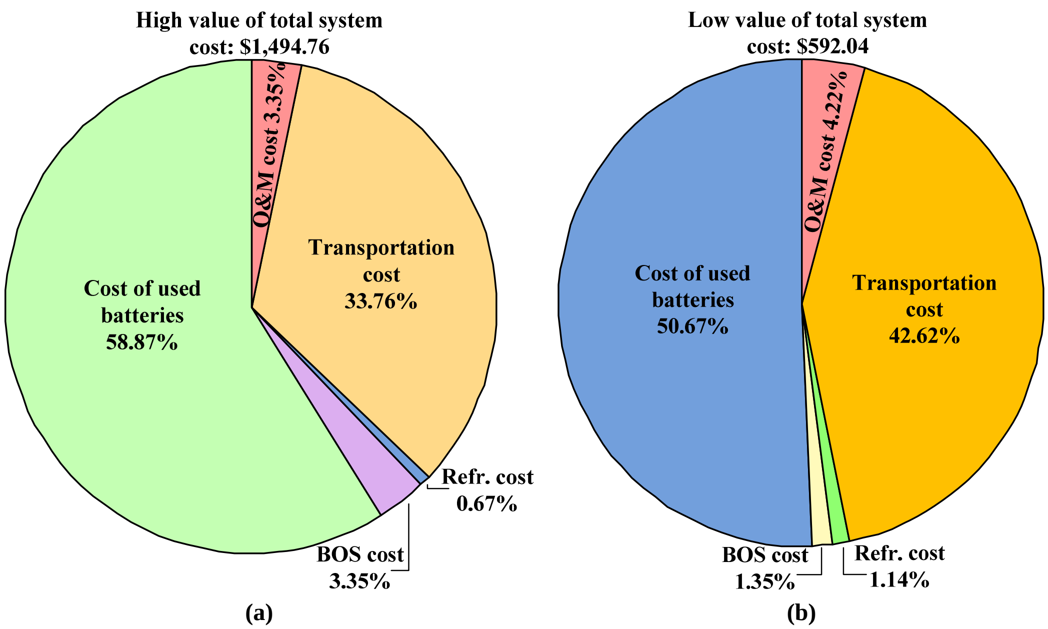


Fig. 7.1. Cost breakdown for high (a) and low (b) values of time-of-use energy cost management for residential applications.

For medium size commercial and industrial (C&I) users, 1 MW peak power capability is reasonable to avoid high price energy purchases during peak demand hours. The discharge duration can be 3–6 hours depending on the peak demand hours.[14] Therefore, this study used 1 MW peak power capability with 4 MWh of energy storage capacity for residential application calculations. Table 7.4 shows the cost breakdown for TOU energy cost management for a C&I application, and Fig. 7.2 shows the total cost and cost share components of TOU energy cost management for C&I applications.

Table 7.4. Cost of time-of-use energy cost management application based on 1 MW peak power and 4 MWh storage capacity (commercial/industrial users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$880,000	$50,000	$10,080	$504,680	$50,000
Low value cost	$300,000	$8,000	$6,720	$252,320	$25,000

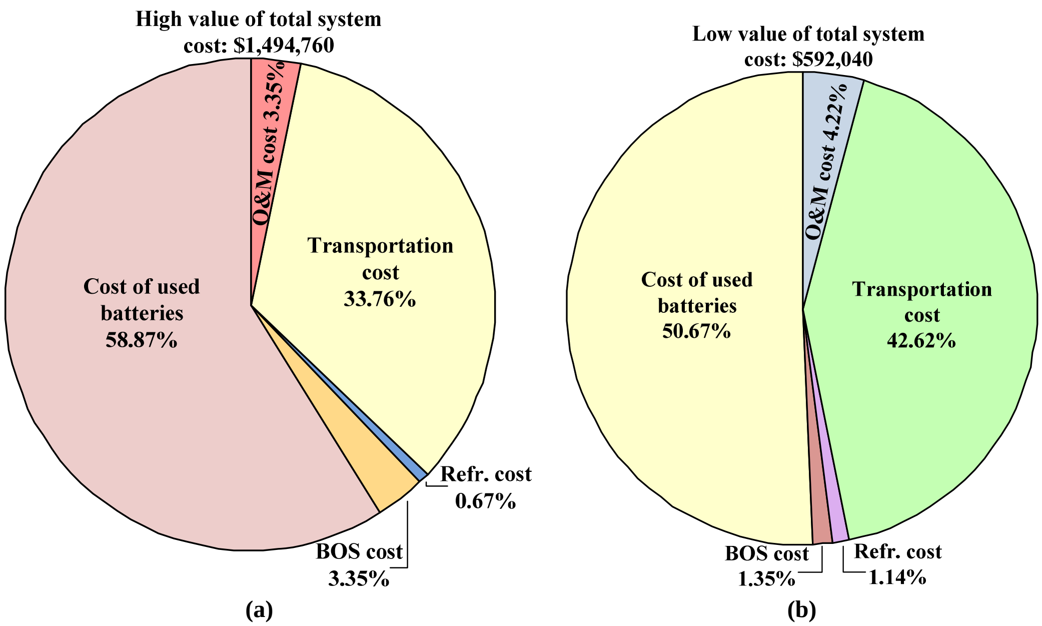


Fig. 7.2. Cost breakdown for high (a) and low (b) values of time-of-use energy cost management for commercial/industrial applications.

7.2 DEMAND CHARGE MANAGEMENT

Demand charge management refers to using storage to reduce demand on the grid during peak electricity demand periods. Energy is stored during off-peak hours and discharged during peak hours. Thus, demand charges can be presented in dollars per kilowatt of power draw, resulting in a separate price for energy. These charges are defined by the consumer rate structure and vary by week and by season. The standard assumption value for the benefit is calculated based on PG&E's Electric Schedule E-19 Medium General Demand-Metered TOU Service tariff (http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-19.pdf). Tables 7.5 and 7.6 are billing examples based on this tariff, with and without storage. Table 7.7 compares the results.

Table 7.5. Electricity bill based on Pacific Gas and Electric's E-19 tariff, without storage

	Hours per year[a]	Demand charge ($/kW-month)	Peak load factor[b]	Demand charges ($/kW-year)	Average load factor	Energy use (kWh-year)	Energy price ($/kWh)	Energy charges ($/kW-year)	Total charges ($/kW-year)
					Summer				
Peak	765	11.59	0.90	62.59	0.80	612	13.458	82.36	144.95
Partial peak	893	2.65	0.80	12.72	0.60	536	9.257	49.57	62.29
Off peak	2,723	6.89	0.60	24.80	0.55	1,497	7.541	112.92	137.72
					Winter				
Partial peak	1,658	1.00	0.80	4.80	0.70	1,160	8.256	95.79	100.59
Off peak	2,723	6.89	0.55	22.74	0.50	1,361	7.286	99.18	121.92
			Total	127.65	0.590	5,166	8.513	439.82	567.47

[a]Approximate values.
[b]Average peak load during all months of the season.

Table 7.6. Electricity bill based on Pacific Gas and Electric's E-19 tariff, with storage

	Hours per year[a]	Demand charge ($/kW-month)	Peak load factor[b]	Demand charges ($/kW-year)	Average load factor	Energy use (kWh-year)	Energy price (¢/kWh)	Energy charges ($/kW-year)	Total charges ($/kW-year)
					Summer				
Peak	765	11.59					13.458		
Partial peak	893	2.65	0.80	12.72	0.60	536	9.257	49.57	62.29
Off peak	2,723	6.89	0.80	33.07	0.82	2,232	7.541	168.35	201.42
					Winter				
Partial peak	1,658	1.00	0.80	4.80	0.70	1,160	8.256	95.79	100.59
Off peak	2,723	6.89	0.55	22.74	0.50	1,361	7.286	99.18	121.92
			Total	73.33	0.604	5,289	7.806	412.89	486.22

[a]Approximate values.
[b]Average peak load during all months of the season.
Note: Storage efficiency = 80.0%.

Table 7.7. Electricity bill comparison for Pacific Gas and Electric's E-19 tariff, with and without storage

	Demand charges ($/kW-year)	Averag e load factor	Energy use (kWh-year)	Energy price (¢/kWh)	Energy charges ($/kW-year)	Total charges ($/kW-year)
With storage ($)	73.3	0.60	5,289	7.81	412.9	486.2
Without storage ($)	127.6	0.590	5,166	8.51	439.8	567.5
Change, with storage ($)	–54.3	+0.014	+123[a]	–0.71	–26.9	–81.2
(%)	–42.6%	2.4%	2.4%	–8.3%	–6.1%	–14.3

[a]Increase due to storage losses.

As shown in the tables, storage leads to reduced demand and energy charges and a lower total energy bill. Table 7.8 shows the benefits for this application under various scenarios.

Table 7.8. Life-cycle present value of demand charge management application

Benefit category	Benefits ($/kW)
Annual benefits	81.25
Life-Cycle Benefit I	658.94
Life-Cycle Benefit II	593.13
Life-Cycle Benefit III	375.64
Life-Cycle Benefit IV	582.61

The demand charge is typically levied on C&I customers, not residential customers. Demand charges are based on each customer's maximum 15-minute power demand on the energy provider's distribution system each month. Therefore, reducing the maximum power demand of the customer through energy storage would reduce the demand charges, too. The peak power rating of this application solely depends on the peak power demanded by the customer. For small commercial users, 50 kW to 200 kW peak power capability would suffice, whereas for large C&I users the peak power could vary from 1 MW to 10 MW, depending on the major energy consuming equipment of the customer. The energy storage capacity of the system depends on the maximum daily demand charge hours (the period of time when the customer is operating at its maximum power demand) per utility tariff. Therefore, storage capacity may vary from 5 hours to 11 hours.[14] This study based calculations on an energy storage system with 200 kW peak power and 1 MWh of storage capacity for small users and 5 MW peak power and 25 MWh storage capacity for larger customers. Table 7.9 shows the costs associated with the demand charge management application for small C&I users, and Fig. 7.3 shows the total cost and cost share components of the demand charge management application for small C&I users.

Table 7.10 shows the costs associated with the demand charge management application for larger C&I users, and Fig. 7.4 shows the total costs and cost share components of the demand charge management application for larger C&I users.

Table 7.9. Cost of demand charge management application based on 200 kW peak power and 1 MWh storage capacity (small commercial/industrial users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$220,000	$10,000	$2,520	$126,170	$10,000
Low value cost	$75,000	$1,600	$1,680	$63,080	$5,000

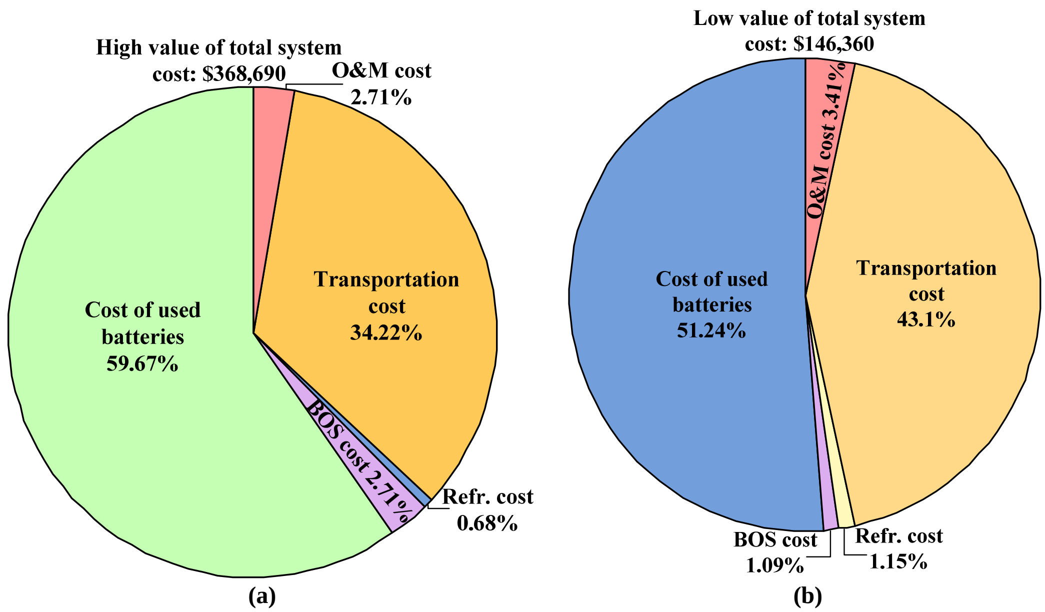


Fig. 7.3. Cost breakdowns for high (a) and low (b) values of the demand charge management application for small commercial/industrial users.

Table 7.10. Cost of demand charge management application based on 5 MW peak power and 25 MWh storage capacity (larger commercial/industrial users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$5,500,000	$250,000	$63,000	$3,154,250	$250,000
Low value cost	$1,875,000	$40,000	$42,000	$1,577,000	$125,000

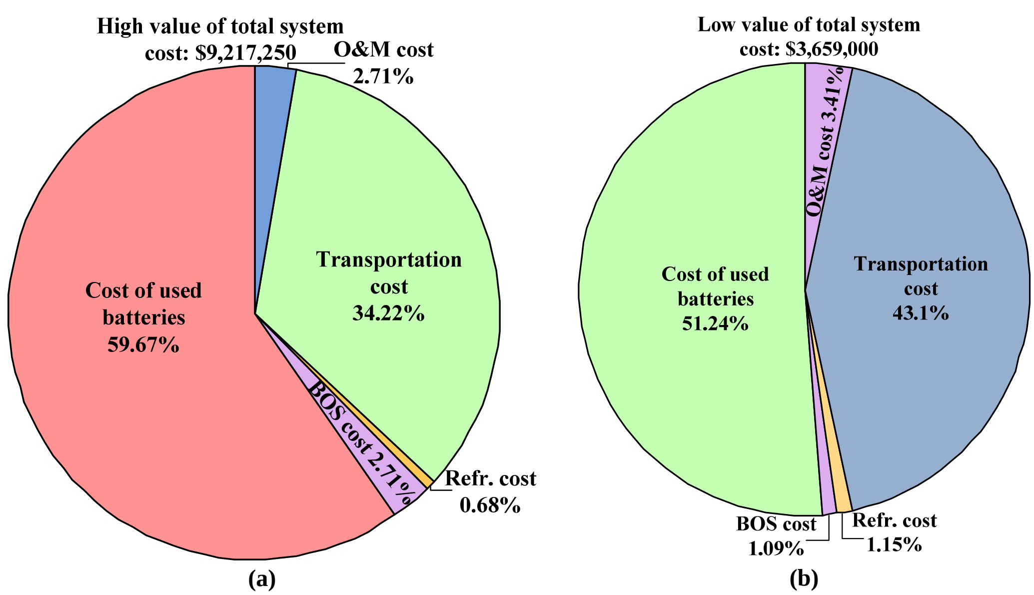


Fig. 7.4. Cost breakdowns for high (a) and low (b) values of the demand charge management application for large commercial/industrial users.

7.3 ELECTRIC SERVICE RELIABILITY

Electric service reliability refers to storage used to manage power outages. The benefit is consumer specific because financial loss due to power outage is highly consumer specific.

Assuming outage hours of 2.5 hours per year and a value of service of $20/kWh,[36] annual reliability benefits can be estimated as follows:

$$\$20/\text{kWh} \times 2.5/\text{year} = \$50/\text{kW-year} .$$

Using this equation with a $10/kWh value and 2.5 outage hours per year,[37–40] the benefit translates into $25/kW-year (the low-end value). Table 7.11 summarizes the life-cycle benefits for selected combinations of operating life and discount rate for the low- and high-end scenarios.

Table 7.11. Life-cycle present value of the electric service reliability application

Benefit category	Low ($/kW)	High ($/kW)
Annual benefits	25	50
Life-Cycle Benefit I	202.75	405.5
Life-Cycle Benefit II	182.5	365
Life-Cycle Benefit III	115.58	231.16
Life-Cycle Benefit IV	179.26	358.53

For this application, the power rating may vary from 1 kW for small under desk UPS devices to 10 MW for facility-wide C&I users. The small under desk UPS can have up to 15 minutes discharge time, resulting in 0.5 kWh capacity. For facility-wide large C&I users, the discharge duration typically varies from 5 minutes to 15 minutes as these facilities usually have diesel backup generators for long outage durations. Therefore, this study considered an electric service reliability application with 10 MW power and 10 minute discharge duration for facility-wide large C&I users (1.67 MWh storage capacity) and 1 kW with 15 minute discharge duration (0.5 kWh capacity) for small C&I users. Table 7.12 provides the costs for a small size electric service reliability application, and Fig. 7.5 shows the cost breakdown and cost share components.

Table 7.13 provides the costs for a large, facility-wide electric service reliability application, and Fig. 7.6 shows the cost breakdown and cost share components.

Table 7.12. Cost of electric service reliability application based on 1 kW peak power and 0.5 kWh storage capacity (small commercial/industrial users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$110	$50	$1.26	$63.08	$50
Low value cost	$37.5	$8	$0.84	$31.54	$25

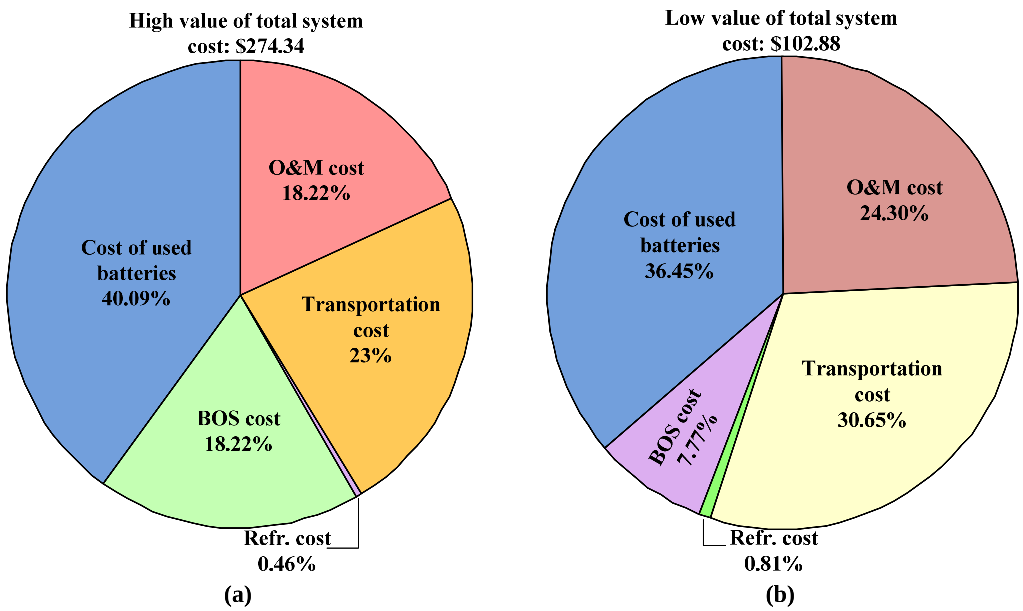


Fig. 7.5. Cost breakdowns for high (a) and low (b) values of the electric service reliability application for a small application.

Table 7.13. Cost of electric service reliability application based on 10 MW peak power and 1.67 MWh storage capacity (large facility-wide commercial/industrial users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$367,400	$500,000	$4,208.4	$210,703.9	$500,000
Low value cost	$125,250	$80,000	$2,805.6	$105,343.6	$250,000

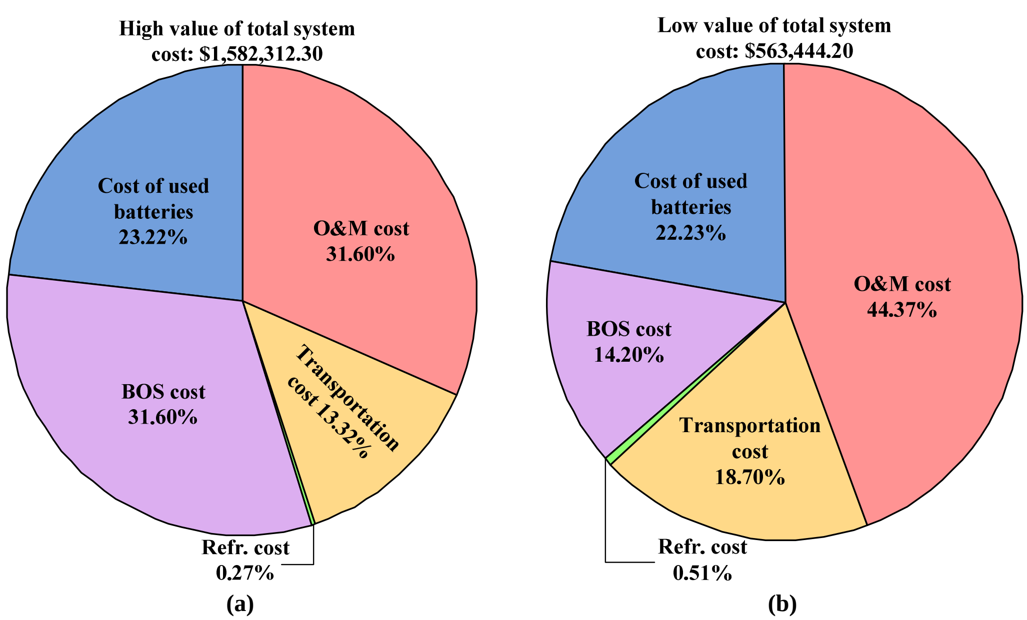


Fig. 7.6. Cost breakdowns for high (a) and low (b) values of the electric service reliability application for facility-wide larger commercial/industrial users.

7.4 ELECTRIC SERVICE POWER QUALITY

The electric service power quality benefit is end-user specific, and if energy storage reduces financial losses associated with power quality anomalies, it can be considered beneficial. Assuming $5 per event for each kilowatt of end user peak load and assuming that energy storage enables avoiding 10 power quality events per year, the annual benefit is $50/kW-year. Table 7.14 shows the lifetime benefits.

Table 7.14. Life-cycle present value of electric service power quality application

Benefit category	Benefits ($/kW)
Annual benefits	50
Life-Cycle Benefit I	405.5
Life-Cycle Benefit II	365
Life-Cycle Benefit III	231.16
Life-Cycle Benefit IV	358.53

The power rating of the electric service power quality application is considered to be 1 kW for residential applications and 10 MW for large scale C&I applications. For harmonic suppression and power correction, typically 10 seconds to 60 seconds discharge duration is sufficient. This study considers 30 seconds of discharge duration for both the residential and the C&I applications (0.0083 kWh storage capacity for residential and 83.33 kWh for C&I applications). Table 7.15 shows the cost breakdown of electric service power quality for residential applications, and Fig. 7.7 shows the total cost and cost share components.

Table 7.16 shows the cost breakdown of electric service power quality for large scale C&I users, and Fig. 7.8 shows the total cost and cost share components.

Table 7.15. Cost of electric service reliability application based on 1 kW peak power and 0.0083 kWh storage capacity (residential users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$1.83	$50	$0.021	$1.05	$50
Low value cost	$0.6225	$8	$0.014	$0.52	$25

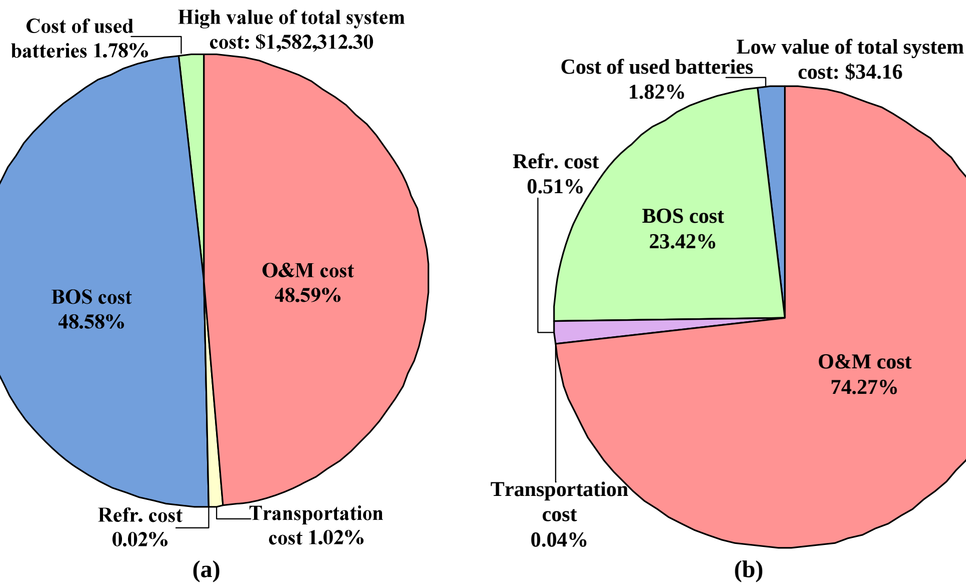


Fig. 7.7. **Cost breakdowns for high (a) and low (b) values of the electric service power quality application for residential users.**

Table 7.16. Cost of electric service reliability application based on 10 MW peak power and 83.33 kWh storage capacity (large scale commercial/industrial users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$18,332.6	$500,000	$210	$10,513.74	$500,000
Low value cost	$6,249.73	$80,000	$140	$5,256.87	$250,000

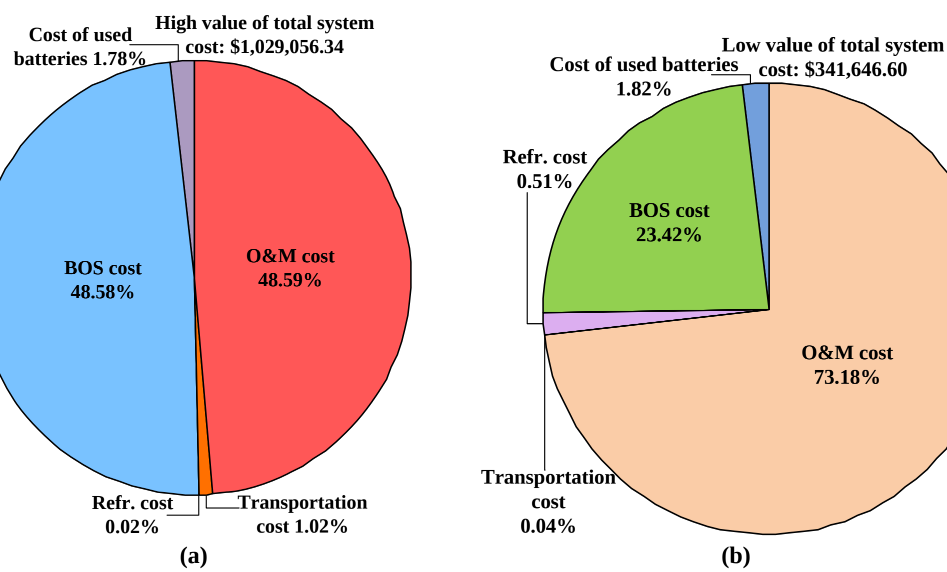


Fig. 7.8. **Cost breakdowns for high (a) and low (b) values of the electric service power quality application for large scale commercial/industrial users.**

8. RENEWABLE INTEGRATION APPLICATIONS

8.1 RENEWABLES ENERGY TIME SHIFT

In renewables time shifting, storage resources are used to store energy produced by renewable energy sources such as wind or photovoltaics (renewables) to be sold at a later time when it is more valuable. The following factors can be used to estimate the benefit (again, California has been used for examples in this report).

- Avoided cost of purchasing electric energy from the wholesale market
- Incremental benefit of renewable energy time shift

The wholesale spot energy price differential forecast for the on-peak and off-peak time frames during weekdays in California for 2009 is summarized in Fig. 8.1.

(a) Monthly price "bins"

	Month											
Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
12:00 p.m.–5:00 p.m.	85.1	74.5	77.6	94.6	100.3	118.0	148.2	163.1	142.5	99.1	104.5	105.9
1:00 a.m.–6:00 a.m.	–51.8	–44.4	–46.2	–61.2	–42.7	–35.2	–55.1	–69.7	–77.0	–61.3	–61.5	–72.9
Storage losses[a]	–10.4	–8.9	–9.2	–12.2	–8.5	–7.0	–11.0	–13.9	–15.4	–12.3	–12.3	–14.6
Net time-shift benefit	23.0	21.1	22.1	21.1	49.1	75.7	82.1	79.4	50.1	25.5	30.7	18.4

(b) Seasonal

	May–October	November–April
12:00 p.m.–5:00 p.m.	128.5	90.4
1:00 a.m.–6:00 a.m.	–56.8	–56.4
Storage losses[a]	–11.4	–11.3
Net time-shift benefit	60.3	22.8

[a]Storage efficiency = 80.0%.
Note: Values expressed in units of $/MWh.

(c) Annual

	Hours	Value[b]
May–October	651.8	39,323
November–April	651.8	14,830
Total	1.304	54.152

[b]Net time-shift benefit × hours/year.

Fig. 8.1. Wholesale spot energy price differential, on-peak and off-peak, weekdays, in California for 2009 in dollars per megawatt hours: (a) monthly, (b) seasonal, and (c) annual.

The variable cost for generation ranges from 4.8¢/kWh for a 45% efficient combined cycle plant, assuming a fuel price of about $5/MMBtu, to 7¢/kWh for a 35% efficient simple cycle combustion turbine plant, assuming a fuel price of $6/MMBtu.

Taking wind generation as an example, the off-peak versus on-peak price differential is estimated as follows, using information from Fig. 8.1.

- Price difference between weekday energy prices during 12:00–5:00 PM and 1:00–6:00 AM
- Time shifting for 3 and 5 hours/day for all weekdays is worth $32.5/kW-year and $54,152/MW-year or $54.2/kW-year

The life-cycle benefits of 3- and 5-hour time shifting for a storage efficiency of 80% and selected combinations of discount rate and operating life for the device are shown in Table 8.1.

Table 8.1. Life-cycle present value of renewables energy time-shift application

Benefit category	5-hour time shift ($/kW)	3-hour time shift ($/kW)
Annual benefits	49.86	29.92
Life-Cycle Benefit I	404.36	242.62
Life-Cycle Benefit II	363.98	218.39
Life-Cycle Benefit III	230.52	138.31
Life-Cycle Benefit IV	357.52	214.51

The power rating of this application is based on the size of the renewable installation. For example, for a renewable energy time-shift application for a residential photovoltaic system, the power rating of the storage system can be about 1 kW. For utility level large scale applications, a wind turbine's power rating can be on the order of 3 MW to 5 MW. Therefore, this study used a 1 kW power rating for residential applications and 4 MW for large scale renewable integrations. The discharge duration for the renewables energy time-shift application is based on the renewable energy intermittencies, energy cost/price differential, and the VOCs and might be from 3 hours to 5 hours.[14] Therefore, this study used 4 hours of discharge duration for both the residential and large scale utility applications. Table 8.2 shows the cost breakdown of renewable energy time-shift applications for residential users, and Fig. 8.2 shows the total cost and cost share components.

Table 8.2. Cost of renewables energy time-shift application based on 1 kW peak power and 4 kWh storage capacity (residential users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$880	$50	$10.08	$504.68	$50
Low value cost	$300	$8	$6.72	$252.32	$25

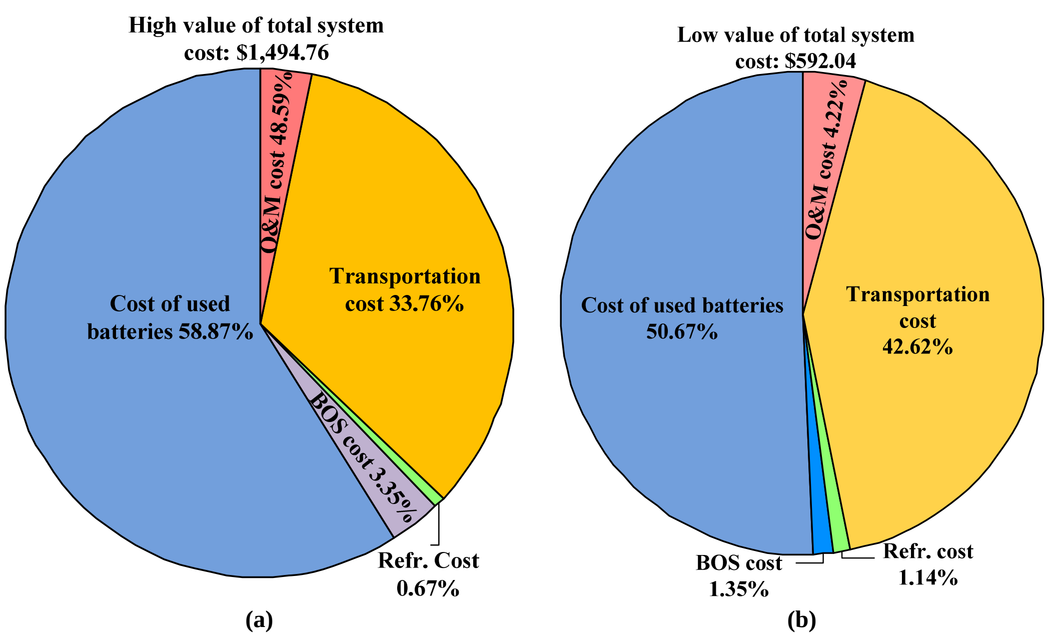


Fig. 8.2. Cost breakdowns for high (a) and low (b) values of the renewables energy time-shift application for residential users.

Table 8.3 provides the cost breakdown of the renewable energy time-shift application for utility level integrations, and Fig. 8.3 shows the total cost and cost share components.

Table 8.3. Cost of renewables energy time-shift application based on 4 MW peak power and 16 MWh storage capacity (large scale utility level integrations)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$3,520,000	$200,000	$40,320	$2,018,720	$200,000
Low value cost	$1,200,000	$32,000	$26,880	$1,009,280	$100,000

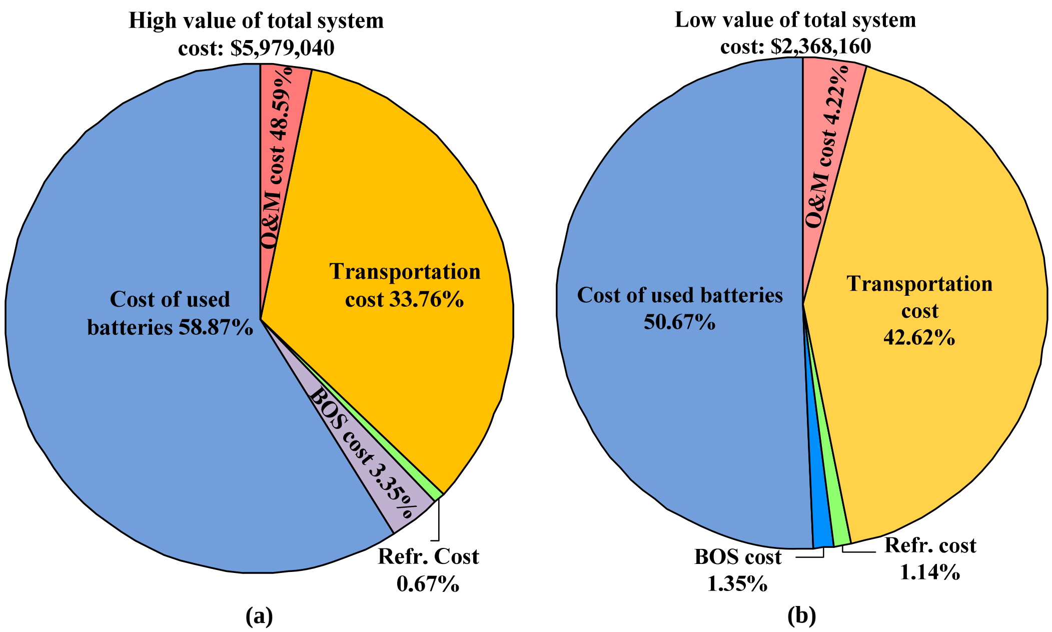


Fig. 8.3. Cost breakdowns for high (a) and low (b) values of the renewables energy time-shift application for large scale utility level renewable integrations.

8.2 RENEWABLES CAPACITY FIRMING

Renewables capacity firming refers to the cost that can be avoided for other electric supply capacity because of the constant supply of renewable energy through energy storage.

The incremental benefit of renewables capacity firming is based on the avoided cost of $120/kW-year. For PV, the assumed capacity credit before firming is 0.4 and after firming is 1.0 for an increase of 0.6 kW per kilowatt of rated capacity. The resulting benefit is $72/kW-year.

The energy related benefit and total annual benefits are summarized in Tables 8.4 and 8.5.

Table 8.4. Energy component benefit of renewables capacity firming application

	Photovoltaics		Wind generation	
	Summer	Winter	Summer	Winter
Net unit benefit ($/MWh)[a]	60.3	22.2	60.3	22.2
(¢/kWh)	6.03	2.22	6.03	2.22
Energy time shift (hours/day)[b]	2.5	2.5	3.5	3.5
Days/year[c]	130	130	130	130
Hours/year	326	326	456	456
Net seasonal benefit ($/kW-year)	19.7	7.2	27.5	10.1
Net annual benefit ($/kW-year)	26.9		37.6	

[a]On-peak energy price minus off-peak energy price minus cost for storage losses. Does *not* include consideration of storage variable operating cost.
[b]This criterion is based on the storage discharge duration.
[c]This criterion is based on the definition of peak demand period.

Table 8.5. Total annual renewables capacity firming benefit

Renewable energy type	Storage energy discharge duration	Renewables effective capacity[a]		Storage incremental value ($/kW-year)		
		Without firming	With Firming	Capacity[b]	Energy	Total
Photovoltaics	2.5	0.40	1.00	72.0	26.9	98.9
Wind	3.5	0.25	1.00	90.0	37.6	127.6

[a]During peak demand periods.
[b]Assuming $120 per kW-year for combustion turbine based generation.

The total life-cycle benefits for wind for selected values of the operating life and discount rate parameters are summarized in Table 8.6.

Table 8.6. Life-cycle present value of renewables capacity firming benefit

Benefit category	Benefits ($/kW)
Annual benefits	127.6
Life-Cycle Benefit I	1,034.84
Life-Cycle Benefit II	931.48
Life-Cycle Benefit III	589.93
Life-Cycle Benefit IV	914.96

This application's power rating is the same as that for the renewables energy time-shift application. Therefore, for analysis purposes 1 kW was used for residential applications and 4 MW for large scale utility level applications. The discharge duration requirement depends on the low and high values for renewable generation/peak load correlation,[14] which is typically 2 to 4 hours. For a reasonable storage capacity, 3 hours was used, which results in 3 kWh for residential applications and 12 MWh for large scale renewable integrations. Table 8.7 provides the cost breakdown for the renewable energy time-shift application for residential installations, and Fig. 8.4 shows the total cost and cost share components.

Table 8.7. Cost of renewables capacity firming application based on 1 kW peak power and 3 kWh storage capacity (residential users)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$660	$50	$7.56	$378.51	$50
Low value cost	$225	$8	$5.04	$189.24	$25

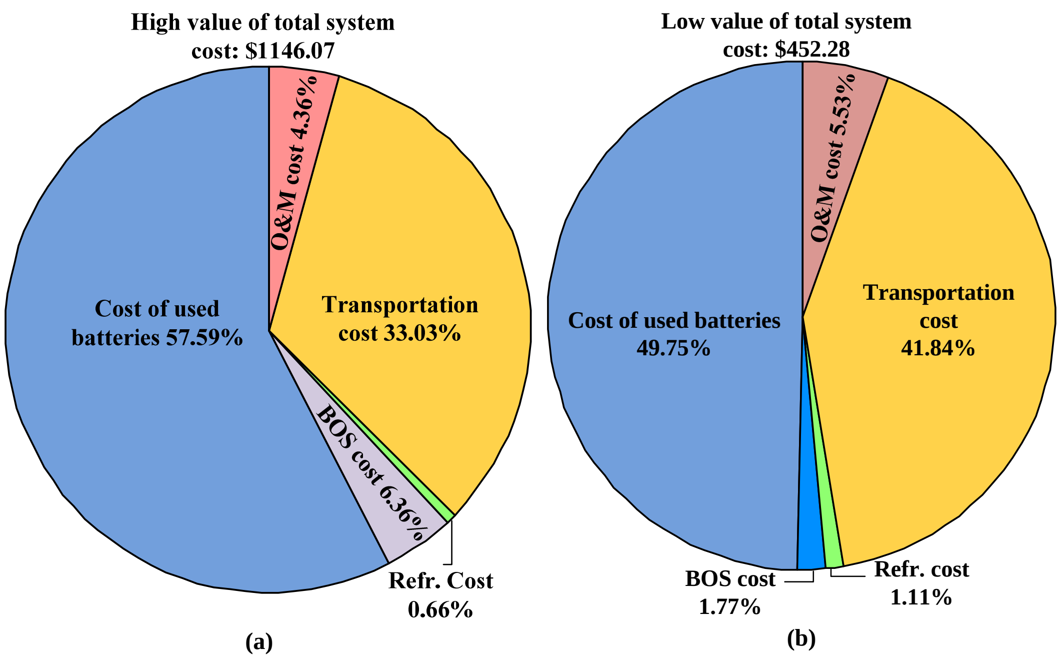


Fig. 8.4 Cost breakdowns for high (a) and low (b) values of the renewables capacity firming application for residential installations.

Table 8.8 provides the cost breakdown for the renewables capacity firming application for utility level integrations, and Fig. 8.5 shows the total cost and cost share components.

Table 8.8. Cost of renewables capacity firming based on 4MW peak power and 12 MWh storage capacity (large scale integrations)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$2,640,000	$200,000	$30,240	$1,514,040	$200,000
Low value cost	$900,000	$32,000	$20,160	$756,960	$100,000

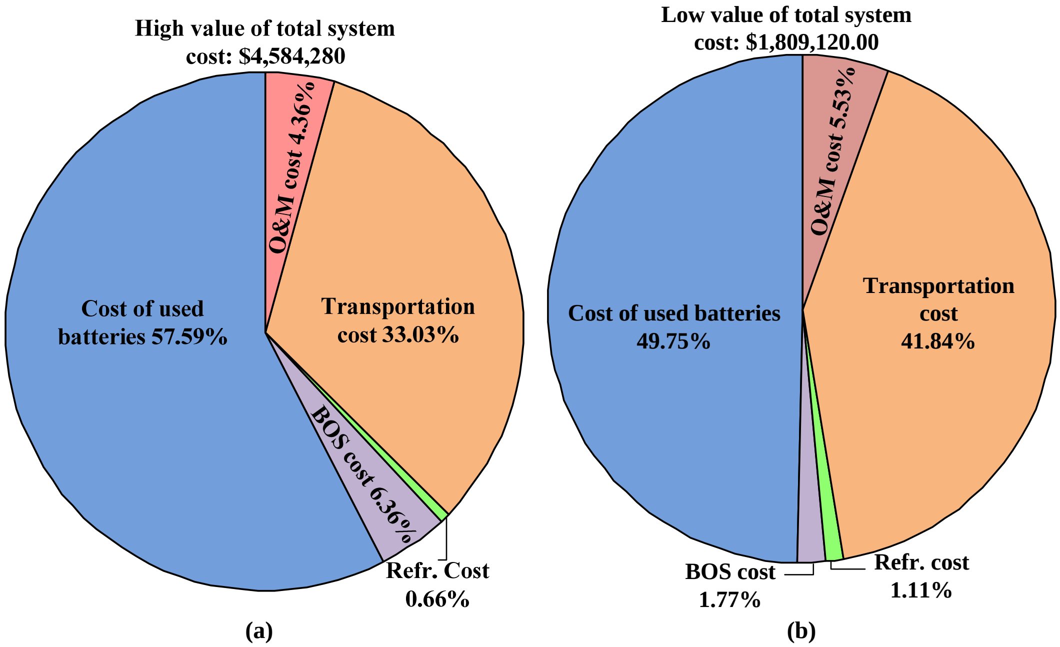


Fig. 8.5. Cost breakdowns for high (a) and low (b) values of the renewables capacity firming applications for large scale renewable integrations.

8.3 WIND GENERATION GRID INTEGRATION

Energy storage can mitigate concerns about using what are sometimes perceived as variable/intermittent energy sources (renewables)—especially in the case of wind energy—fostering greater confidence in their use and grid integration. This section deals with energy storage support for the following wind generation grid integration issues.

- Short-duration applications
  - Reduce output volatility
  - Improve power quality
- Long-duration applications
  - Reduce output variability
  - Provide transmission congestion relief
  - Provide backup for unexpected wind generation shortfall
  - Reduce minimum load violations

The benefits associated with storage used for each type of application vary and thus should be estimated separately.

The benefit of reduced output volatility is avoided cost for additional area regulation service to accommodate the volatility. Area regulation capacity needed to accommodate wind generation is required during the six most productive months for wind generation depending on the region. Thus, the benefit estimate is half of the annual operating cost. Eyer and Corey estimated the generic benefit for this category to be $750/kW for 10 years).[14]

The benefit for improved power quality is specific to the location, wind resource, and wind turbine type. Thus, an estimate of a generic benefit is not helpful.

Wind generation output variability involves changes that occur over minutes to hours. The benefit of reducing aggregate wind output variability is the avoided cost of additional load-following service. Assuming such service will be provided by a combined cycle generation plant for 6 hours per day, the marginal cost of additional service is $50/MW per service hour. The annual benefit (estimated for 6 hours/day/week for 26 weeks) is $54,600/MW per year or $54.6/kW-year, and the generic life-cycle benefit is $398.6/kW.

Transmission congestion relief cannot be easily generalized. In California, cumulative wind generation capacity additions were estimated at 5,200 MW for 2010 and 10,600 MW for 2020 (Table 8.9). The cost of new generation capacity to accommodate all renewables was estimated at $2.3 billion for 2010 and $6.3 billion for 2020. Assuming that two-thirds of the new transmission cost is due to renewables, the life-cycle benefit (Table 8.9) can be estimated to be the cost to upgrade transmission to accommodate renewables.

Table 8.9. Estimated total transmission cost for wind capacity additions in California

	Parameter	Year	
		2010	**2020**
1	Wind capacity additions (MW, cumulative)	5,200	10,600
2	Transmission total installed cost ($million)	2,300	6,300
3	(Assumed) Portion of transmission attributable to wind generation added	0.667	0.667
4	Transmission cost attributable to wind generation added ($million)	1,534	4,202
5	Transmission *annual* cost for wind generation added ($million)[a]	168.8	462.2
6	Transmission cost for wind generation/wind generation kW ($/kW of wind generation)[b]	295	396
7	Transmission annual cost for wind generation/wind generation kW ($/kW-year of wind generation)	32.5	43.6
8	Transmission life-cycle cost for wind generation ($/kW of wind generation for 10 years)[c]	232.7	312.7
9	(Assumed) kW storage per kW of wind generation	0.50	0.50
10	Life-cycle benefit ($/kW storage, 10 years)	465.4	625.3

[a]Attributable to wind generation. Based on fixed charge rate = 0.11.
[b]Transmission annual cost/wind capacity additions.
[c]10.0%/year discount rate, 2.5%/year escalation rate: PW factor = 7.17.

The value for backup for unexpected wind generation shortfalls is the value of avoiding electric service outages caused by sudden and unexpected drop in wind generation output. This value can be estimated by assuming a value-of-service of $10/kWh (the cost to customers for undelivered energy). Thus, avoiding one outage per year for 10 years will lead to a life-cycle benefit of $100/kW.

Minimum load violation occurs when generation capacity exceeds demand resulting into unused generated energy. The benefit from avoidance of minimum load violation was estimated at $4,949/MW-year or $4.9/kW-year based on the forecasted energy prices in California for 2009 and the following.

- Minimum load violation occurs only for 1% of the time in a given year, which translates into 87.6 hours.

- An energy price of $56.5/MWh, (i.e., the average off-peak price because minimum load violations happen during off-peak hours).

8.3.1 Short-Term Support

Short-term support can comprise either providing power quality or compensating wind speed variations and short-term intermittencies.[41,42] Therefore, the discharge duration for this application can be from 10 to 60 seconds. This study used 30 seconds of discharge duration for this application. The power rating of the energy storage systems directly depends on the power rating of the wind turbine itself. For residential applications 3 kW can be a reasonable peak power capability, whereas for large scale applications about 1.5 MW might be required. Based on the discharge duration, the energy storage capacity can be 0.025 kWh for residential applications and 12.5 kWh for utility level large scale wind integrations.

Table 8.10 provides the cost breakdown for the short-term wind generation grid integration application for small scale residential applications, and Fig. 8.6 shows the total cost and cost share components.

Table 8.10. Cost of short-term wind generation grid integration based on 3 kW peak power and 0.025 kWh storage capacity (small scale integrations)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$5.5	$150	$0.063	$3.15	$150
Low value cost	$1.87	$24	$0.042	$1.57	$75

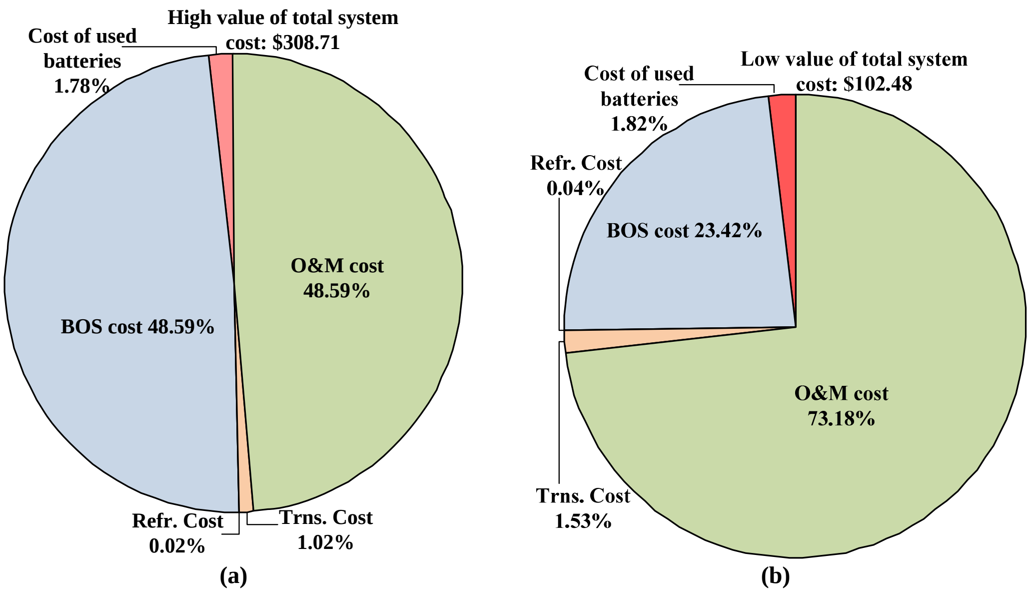


Fig. 8.6. Cost breakdowns for high (a) and low (b) values of the short-term wind generation grid integration application for small scale wind integrations.

Table 8.11 provides the cost breakdown for the short-term wind generation grid integration application for large scale utility level applications, and Fig. 8.7 shows the total cost and cost share components.

Table 8.11. Cost of short-term wind generation grid integration based on 1.5 MW peak power and 12.5 kWh storage capacity (large scale integrations)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$2,750	$75,000	$31.5	$1,577.12	$75,000
Low value cost	$937.5	$12,000	$21	$788.5	$37,500

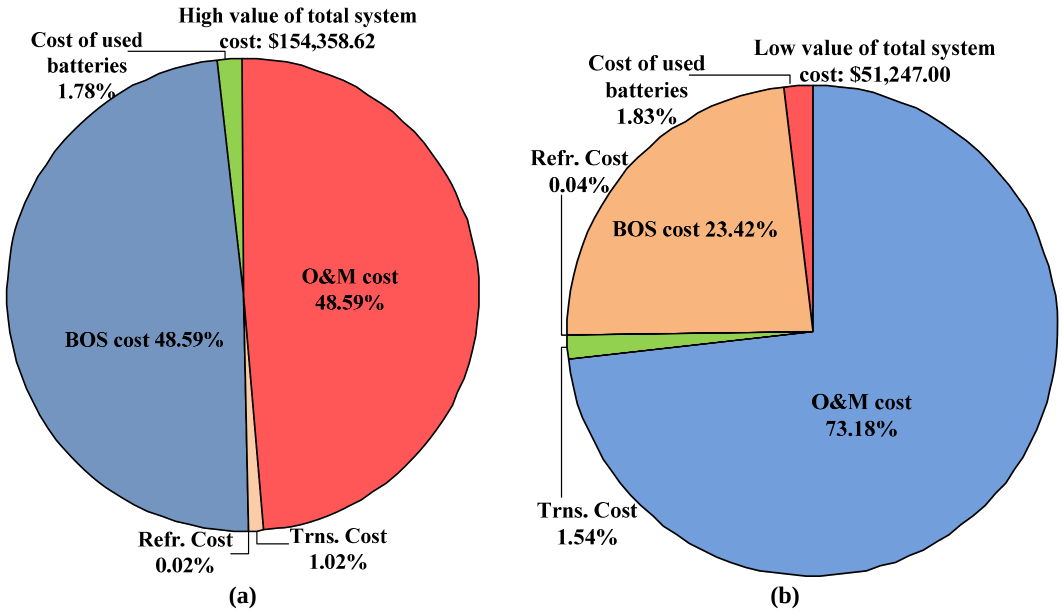


Fig. 8.7. Cost breakdowns for high (a) and low (b) values of the short-term wind generation grid integration application for large scale wind integrations.

8.3.2 Long-Term Support

Long-term support can be in the form of power ramp control, power smoothing, load shifting, and backup or compensation for long-term wind speed intermittencies.[33,34] Therefore, the discharge duration for this application can be from 1 to 6 hours. This study used 4 hours of discharge duration for this application. The power rating of the energy storage systems directly depends on the power rating of the wind turbine itself. For residential applications 3 kW can be a reasonable peak power capability, whereas for large scale applications about 1.5 MW might be required. Based on the discharge duration, the energy storage capacity can be 12 kWh for small scale applications and 6 MWh for utility level large scale wind integrations.

Table 8.12 provides the cost breakdown for the long-term wind generation grid integration application for small scale applications, and Fig. 8.8 shows the total cost and cost share components.

Table 8.13 provides the cost breakdown for the long-term wind generation grid integration application for large scale applications, and Fig. 8.9 shows the total cost and cost share components.

Table 8.12. Cost of long-term wind generation grid integration based on 3 kW peak power and 12 kWh storage capacity (small scale integrations)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$2,640	$150	$30.24	$1,514.04	$150
Low value cost	$900	$24	$20.16	$756.96	$75

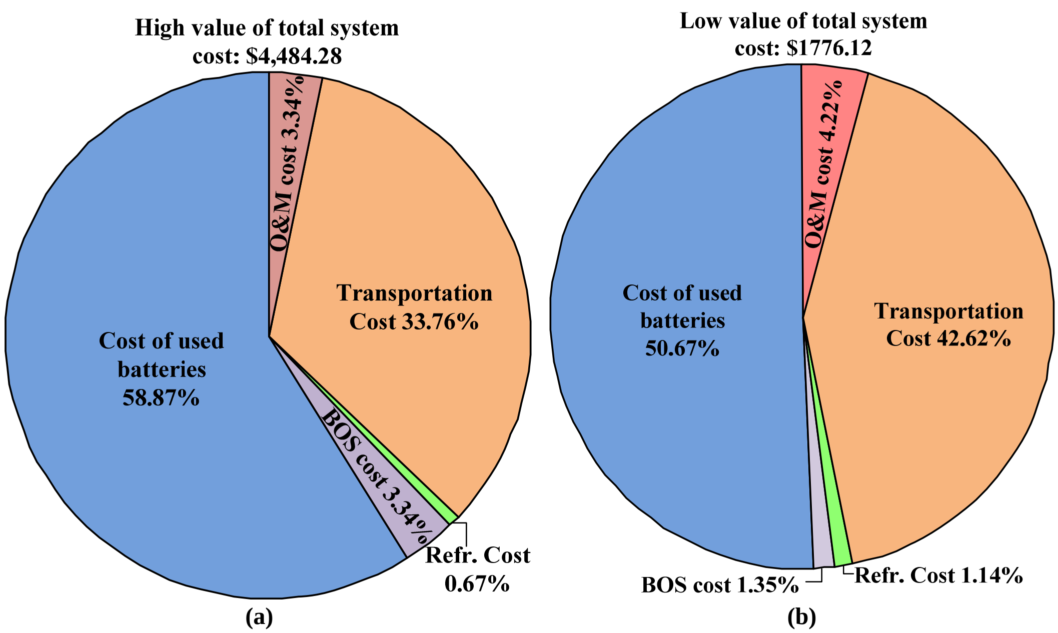


Fig. 8.8. Cost breakdowns for high (a) and low (b) values of the long-term wind generation grid integration application for small scale wind integrations.

Table 8.13. Cost of long-term wind generation grid integration based on 1.5 MW peak power and 6 MWh storage capacity (large scale integrations)

	Cost of used batteries	Balance of system cost	Refurbishment cost	Transportation cost	Operation and maintenance cost
High value cost	$1,320,000	$75,000	$15,120	$757,020	$75,000
Low value cost	$450,000	$12,000	$10,080	$378,480	$37,500

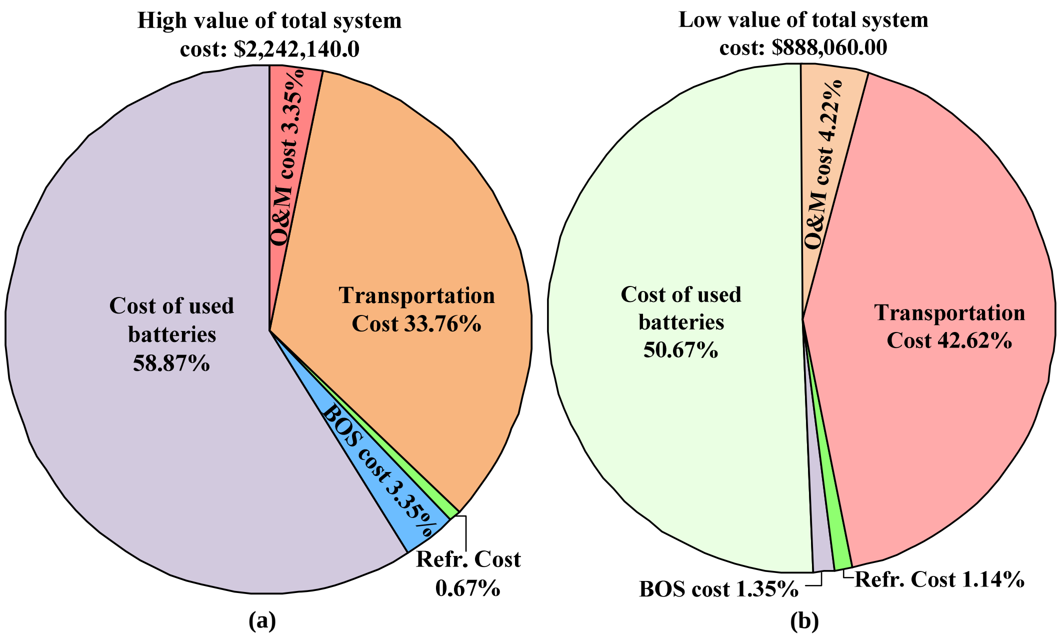


Fig. 8.9. Cost breakdowns for high (a) and low (b) values of the long-term wind generation grid integration application for large scale wind integrations.

9. INCIDENTAL BENEFITS

9.1 INCREASED ASSET UTILIZATION

Energy storage can enable increased capacity utilization resulting in increased asset utilization. The benefit is that the break-even point is achieved sooner than for normal asset utilization. Because this benefit is circumstance specific, it cannot be estimated.

9.2 AVOIDED TRANSMISSION AND DISTRIBUTION ENERGY LOSSES

T&D losses tend to be lower at night when loading is light and temperature is low and higher during the day when loading is heavy and temperature is high. The benefit of energy storage can be estimated by estimating the cost of losses to deliver energy in real time during peak hours and the cost of losses to deliver energy in off-peak hours if storage is charged with grid energy. The benefits will be higher if storage is charged with energy generated locally.

9.3 AVOIDED TRANSMISSION ACCESS CHARGES

Transmission access charges are the charges customers pay for the costs incurred by utilities to own and operate the transmission facilities needed to deliver electricity.

In the Midwest, transmission access charges range from $25 to 30/kW-year, while in California the transmission access charges are about $40/kW-year. If energy storage enables a 50% reduction in transmission access charges at ~$20/kW-year, the life-cycle benefit can be estimated by multiplying $20 with a PV factor of 7.3 or 8.11.

9.4 REDUCED TRANSMISSION AND DISTRIBUTION INVESTMENT RISK

The risk associated with investment in T&D upgrades or expansion is difficult to assess; however, it is considered low for most upgrades. Storage can be used as a hedging technique to reduce perceived risk, but the benefit is highly location specific and cannot be estimated.

9.5 DYNAMIC OPERATING BENEFITS

The generation operating cost is reduced if generation equipment has fewer startups, operates at a constant output, and operates at its rated output for most of the time when in use. Energy storage, being part of the electric supply system, can lead to reduced generation operating cost. Because the benefit is specific to the generation mix in a given region, it cannot be estimated.

9.6 REDUCED FOSSIL FUEL USE

Energy storage can lead to reduced use of fossil fuels due to more efficient fossil-fuel-based generation, dynamic operation, and generation at low temperatures. For example, the fuel use difference between combined cycle combustion turbine generation with fuel efficiency of 49% requiring 6,965 Btu/kWh of fuel and simple cycle combustion turbine generation with 33% fuel efficiency requiring 10,342 Btu/kWh of fuel is 3,377 Btu/kWh. If storage efficiency is 75%, the net amount of fuel used to generate charging energy for striate is 9,292 Btu/kWh (6,965 Btu/kWh off peak divided by 0.75). This results in a fuel use reduction of 1,055 Btu/kWh.

Because one gallon of diesel is equivalent to 129,800 Btu, the reduction of 1,055 Btu/kWh translates into 36.6 cc/kWh. This can be easily used to calculated reductions in CO_2 by assuming decane as a model for diesel.

9.7 REDUCED AIR EMISSIONS FROM GENERATION

Energy storage can definitely improve the efficiency of energy generation and transmission and result in significant greenhouse gas emission reductions. Table 9.1 shows results for the following two common scenarios.

- Charge storage using off-peak electricity from a natural-gas-fueled combined cycle combustion turbine to offset use of natural gas fueled simple cycle combustion turbine on-peak
- Charge storage using off-peak electricity from a modern coal-fueled generation to offset use of natural gas fueled simple cycle combustion turbine on-peak

Table 9.1. Avoided emissions through energy storage

Scenario	Off-peak/charging		On-peak/avoided		Difference[a]	
	CO_2 (lb/MWh)	NO_x (lb/MWh)	CO_2 (lb/MWh)	NO_x (lb/MWh)	CO_2 (lb/MWh)	NO_x (lb/MWh)
Charge: combined cycle Avoid: Simple cycle CT[b]	922	0.260	1,131	0.320	+98.3 (+8.7%)	+0.027 (+8.3%)
Charge: advanced coal Avoid: simple cycle CT	2,222	3.620	1,131	0.320	+1.832 (+162%)	+4.51 (+1,108%)

[a]These values reflect additional fuel used for generation required to make up for energy losses for storage whose efficiency = 75.0%.
[b]CT = combustion turbine.
Source: Hadley, S. W., and Van Dyke, J. W., *Emissions Benefits of Distributed Generation in the Texas Market,* Oak Ridge National Laboratory Report, ORNL/TM-2003/100, April 2003.

While a price cannot be directly ascribed to a given type of air emission, it is possible to estimate it in terms of “natural gas not used as a fuel” or “carbon capture and sequestration.”

Because 44 lb of CO_2 is produced from burning 16 lb of natural gas, a 98.3 lb/MWh CO_2 prevention reflects a saving of 35.7 lb/MWh of natural gas.

9.8 FLEXIBILITY

Energy storage definitely introduces flexibility for both energy generators and consumers, enabling them to respond to changing circumstances and providing a means to hedge risks. However such risk hedging is highly circumstance specific and impossible to estimate.

9.9 COMMUNITY ENERGY STORAGE

Time of use energy management (peak shaving) is the most promising application for community energy storage (CES). Time of use energy management makes great sense where communities install energy storage systems controlled for peak shaving and indirect benefits to the distribution and transmission system such as upgrade deferral, and reserve supply capacity, may be realized. Where markets allow aggregation and smart grid communication infrastructure is implemented between utilities, ISOs, and CES systems, ISOs could aggregate and control CES units to provide several ancillary services.

Electric service reliability and power quality are not major issues for most consumers in the United States. The exceptions are specialized commercial and industrial consumers and infrequently occurring long term failures caused by inclement weather and catastrophic events. Most blackouts last only a few hours or less and would require a disproportionate investment relative to the benefit. Large commercial and industrial concerns are more likely to capture benefits from power quality improvement or power factor correction, than the residential customer side of the meter, but were not the focus of this study.

10. ECONOMIC FEASIBILITY

10.1 RESULTS OF ANALYSIS

Sects. 5 through 9 presented individual assessments of benefits and system costs for a variety of applications ranging from wholesale to retail markets, from utility size to residential customer scales, and from generation to distribution. Figures 10.1 through 10.3 summarize the life-cycle benefits of all the applications for the three combinations of operating life and discount rate discussed in previous sections. Substation on-site power and wind integration have been omitted from the figures and tables in this chapter. Substation on-site power is not included because its discussion in Sect. 7 did not include an estimate of the PV of life-cycle benefits. Wind integration is not included because it is a broad concept encompassing multiple applications and its potential value is difficult to summarize meaningfully in a single figure.

In every case, the T&D upgrade deferral application yields, by far, the highest life-cycle benefits. In contrast, the other grid-related applications (transmission support and transmission congestion deferral) have very low life-cycle benefits compared to the other applications considered. The high-value case of regulation life-cycle benefits would be second on the ranking. However, this result hinges upon the prices at which the combination of regulation up and regulation down services were clearing the CAISO market in 2006. The observed average price for 2010 ($10.6/MWh) was much lower than the one considered for the low-end estimate in Table 5.3 ($25/MWh). Avoiding the construction of new capacity, in both the wholesale market and the systems designed to support intermittent renewables, results in higher values than energy time shifting.

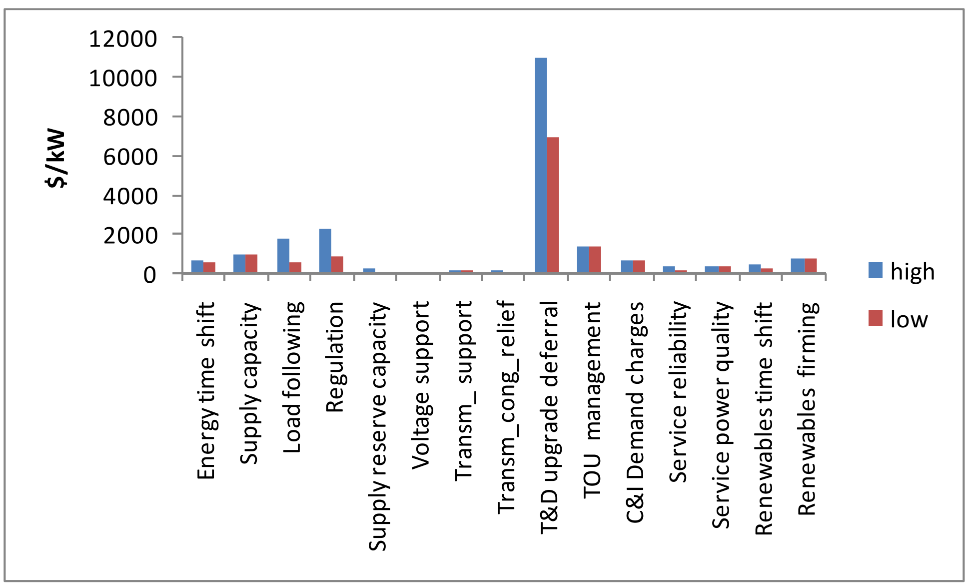


Fig. 10.1. Life-cycle benefit summary (10 years' operating life and 4.18% discount rate).

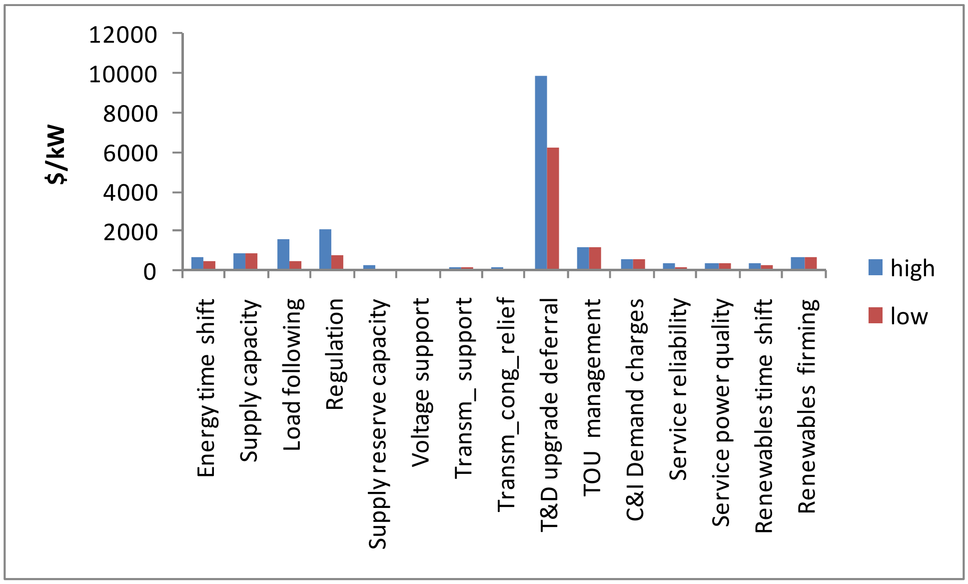


Fig. 10.2. Life-cycle benefit summary (10 years' operating life and 6.41% discount rate).

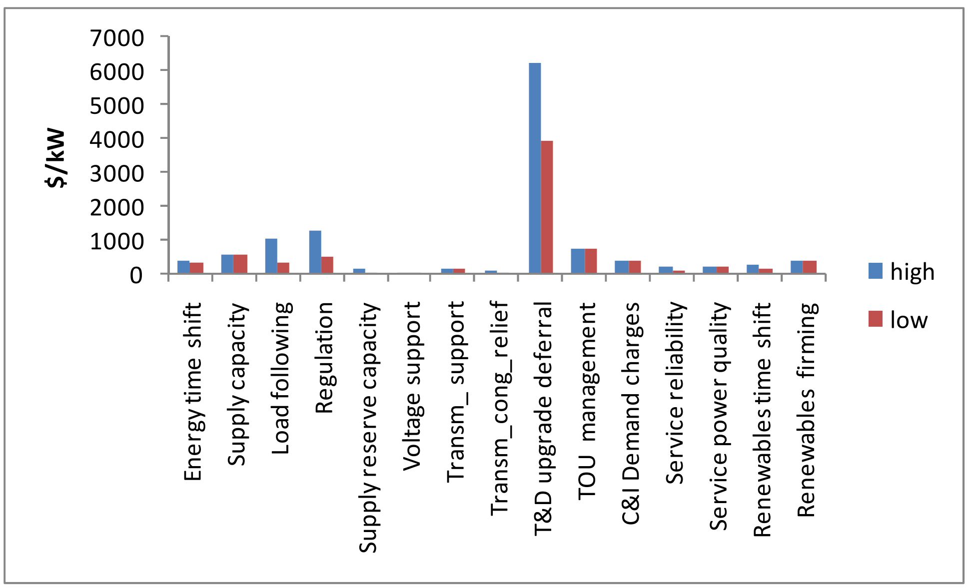


Fig. 10.3. Life-cycle benefit summary (5 years' operating life and 3.22% discount rate).

No conclusions can be drawn about the desirability of a given application without considering both its benefits and the system costs for the size indicated as typical for the application. Since some cost elements are expressed in dollars per kilowatt-hour (used batteries, refurbishment, and transportation) and others in dollars per kilowatt (balance of system, O&M), the ratio of peak power to energy storage capacity is a crucial parameter to determine whether the investment would produce a positive net return over its lifetime. The cost per unit of storage capacity ($140/kWh to $349/kWh according to the values presented in Table 10.1 is much higher than the cost per unit of peak power ($33/kW to $100/kW on a system with an operating life of 5 years). Therefore, those battery systems with low ratios of peak power to storage capacity (i.e., applications which require large discharge durations) will be relatively more expensive to install.

Table 10.1 summarizes typical sizes, high value system costs, and low value system costs for all of the applications considered in this report.

Table 10.1. Size and system cost summary of all applications

Application	Typical size	High value of system cost	Low value of system cost
Electric energy time shift	1 MW, 5 MWh	$1,843,450	$731,800
Electric supply capacity	1 MW, 4 MWh	$1,495,480	$592,040
Load following	1 MW, 3 MWh	$1,146,070	$452,289
Area regulation	20 MW, 5 MWh	$3,743,450	$908,800
Electric supply reserve capacity	50 MW, 50 MWh	$22,434,500	$8,638,000
Voltage support	1 MW, 500 kWh	$274,345	$102,880
Transmission support	50 MW, 16.67 MWh	$10,512,662.30	$3,706,244.5
Transmission congestion relief	20 MW, 80 MWh	$29,895,200	$11,840,800
Transmission and distribution upgrade deferral (50th percentile)	1 MW, 4 MWh	$1,494,760	$592,040
Substation on-site power	4.4 kW, 26.4 kWh	$9,651.49	$3,834.86
Time-of-use (TOU) energy cost management, small scale residential applications	1 kW, 4 kWh	$1,494.76	$592.04
TOU energy cost management, medium size commercial/industrial applications	1 MW, 4 MWh	$1,494,760	$592,040
Demand charge management, small users	200 kW, 1 MWh	$368,690	$146,360
Demand charge management, large users	5 MW, 25 MWh	$9,217,250	$3,659,000
Electric service reliability, small users	1 kW, 0.5 kWh	$274.34	$102.88
Electric service reliability, facility-wide commercial/industrial applications	10 MW, 1.67 MWh	$1,582,312.30	$563,444.20
Electric service power quality, residential users	1 kW, 0.0083 kWh	$102.9	$34.16
Electric service power quality, large scale commercial/ industrial users	10 MW, 83.33 kWh	$1,029,056.34	$341,646.60
Renewables energy time shift, small scale integrations	1 kW, 4 kWh	$1,494.76	$592.04
Renewables energy time shift, large scale integrations	4 MW, 16 MWh	$5,979,040	$2,368,160
Renewables capacity firming, small scale integrations	1 kW, 3 kWh	$1,146.07	$452.28
Renewables capacity firming, large scale integrations	4 MW, 12 MWh	$4,584,280	$1,808,120
Wind generation integration, short-term support, small scale	3 kW, 0.025 kWh	$308.71	$102.48
Wind generation integration, short-term support, large scale	1.5 MW, 12.5 kWh	$154,358.62	$51,247.00
Wind generation integration, long-term support, small scale	3 kW, 12 kWh	$4,484.28	$1,776.12
Wind generation integration, long-term support, large scale	1.5 MW, 6 MWh	$2,242,140	$888,060

Figures 10.4 and 10.5 show cost comparisons for all the applications.

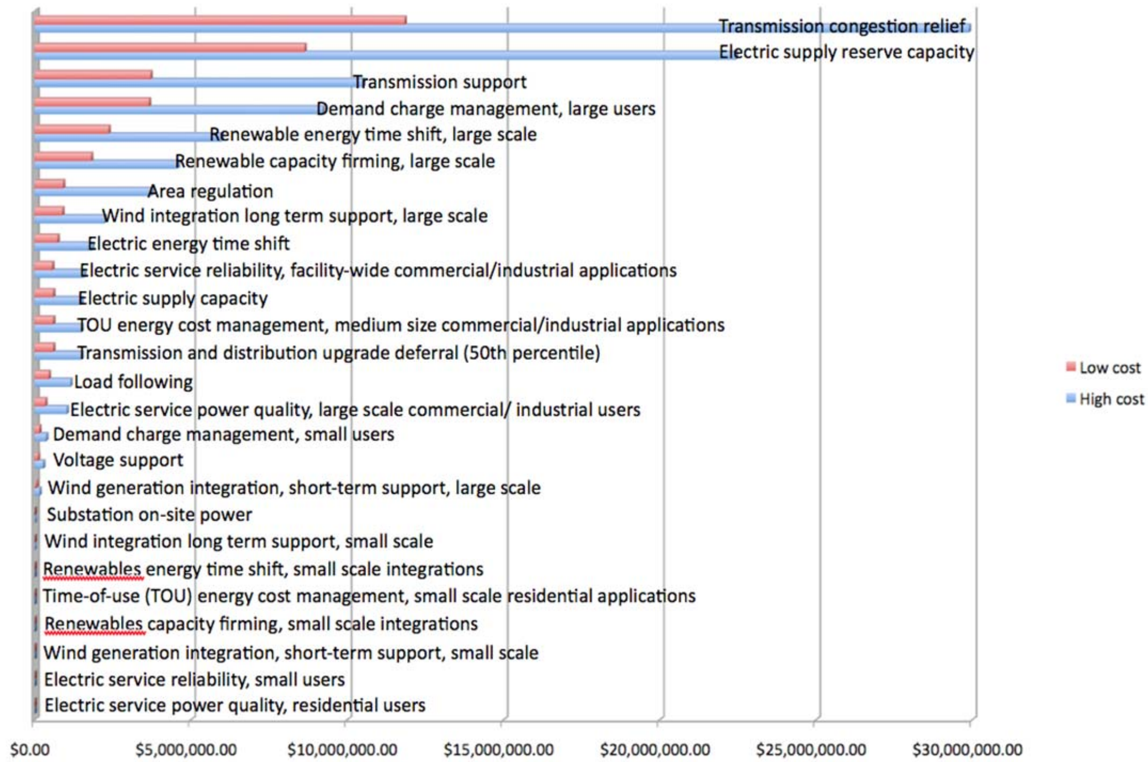


Fig. 10.4. Costs for energy storage in power system support.

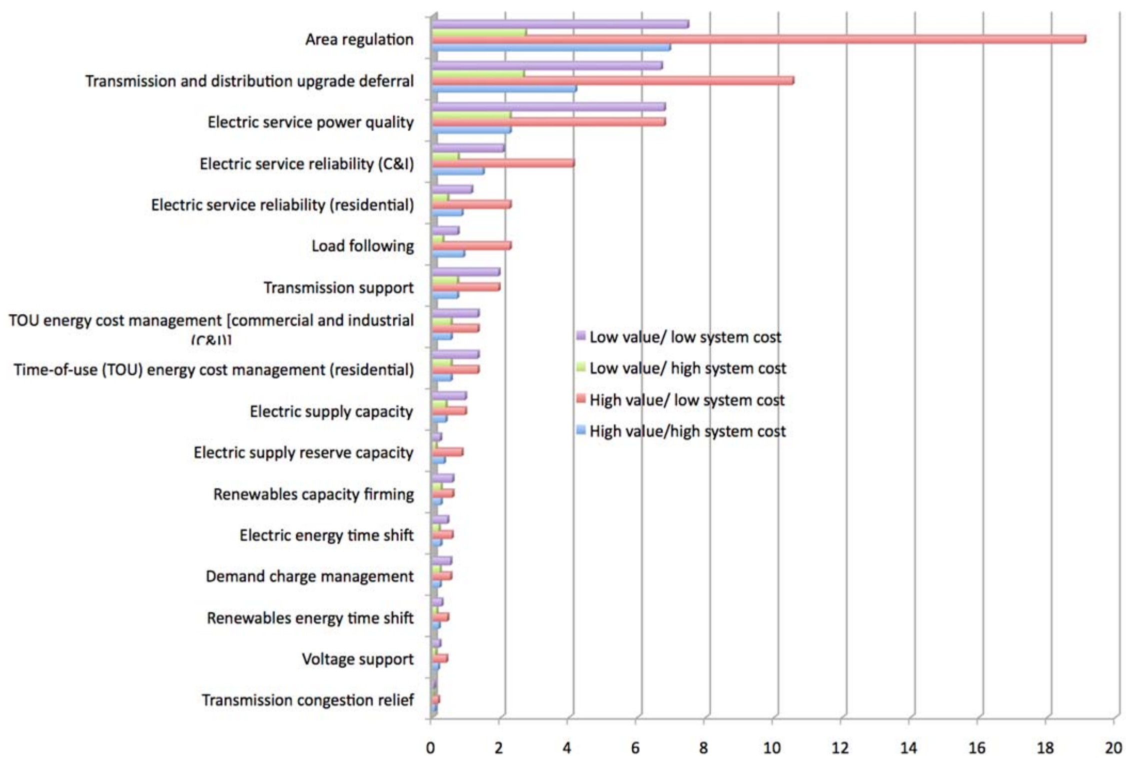


Fig. 10.5. Benefit to cost ratio of various services.

Because the various system sizes differ a lot (from 1 kW for the residential customer applications to 50,000 kW for systems providing supply reserve capacity), values and costs are difficult to compare across applications. Constructing benefit-cost ratios is a more straightforward way of summarizing and comparing results. Tables 10.2 and 10.3 display those ratios for the various high and low value and cost estimate combinations for all the applications. An operating life of 10 years and a discount rate of 4.18% were used in Table 10.2, and an operating life of 5 years and a discount rate of 3.22% in Table 10.3.

Table 10.2. Life-cycle benefit/cost ratios (10-year operating life, discount rate 4.18%)

	High value/high system cost	High value/ low system cost	Low value/ high system cost	Low value/ low system cost
Electric energy time shift	0.38	0.94	0.29	0.72
Electric supply capacity	0.63	1.58	0.63	1.58
Load following	1.49	3.74	0.47	1.19
Area regulation	9.59	24.46	3.74	9.56
Electric supply reserve capacity	0.51	1.29	0.13	0.32
Voltage support	0.12	0.31	0.06	0.16
Transmission support	0.77	1.97	0.77	1.97
Transmission congestion relief	0.10	0.26	0.02	0.06
Transmission and distribution upgrade deferral	7.08	17.73	4.49	11.24
Time-of-use (TOU) energy cost management (residential)	0.88	2.20	0.88	2.20
TOU energy cost management [commercial and industrial (C&I)]	0.88	2.20	0.88	2.20
Demand charge management	0.35	0.87	0.35	0.87
Electric service reliability (residential)	1.25	3.17	0.63	1.59
Electric service reliability (C&I)	1.95	4.99	0.97	2.49
Electric service power quality	2.65	6.85	2.65	6.85
Renewables energy time shift	0.28	0.71	0.17	0.43
Renewables capacity firming	0.39	0.96	0.39	0.96

Table 10.3. Life-cycle benefit/cost ratios (5-year operating life, discount rate 3.22%)

	High value/high system cost	High value/ low system cost	Low value/ high system cost	Low value/ low system cost
Electric energy time shift	0.22	0.55	0.17	0.42
Electric supply capacity	0.37	0.94	0.37	0.94
Load following	0.89	2.25	0.28	0.72
Area regulation	6.92	19.08	2.70	7.45
Electric supply reserve capacity	0.32	0.84	0.08	0.21
Voltage support	0.15	0.39	0.07	0.19
Transmission support	0.71	1.92	0.71	1.92
Transmission congestion relief	0.06	0.15	0.01	0.03

Table 10.3. (continued)

	High value/high system cost	High value/ low system cost	Low value/ high system cost	Low value/ low system cost
Transmission and distribution upgrade deferral	4.17	10.53	2.64	6.68
Time-of-use (TOU) energy cost management (residential)	0.52	1.31	0.52	1.31
TOU energy cost management [commercial and industrial (C&I)]	0.52	1.31	0.52	1.31
Demand charge management	0.20	0.51	0.20	0.51
Electric service reliability (residential)	0.84	2.25	0.42	1.12
Electric service reliability (C&I)	1.46	4.10	0.73	2.05
Electric service power quality	2.25	6.77	2.25	6.77
Renewables energy time shift	0.17	0.42	0.10	0.25
Renewables capacity firming	0.23	0.57	0.23	0.57

The most stringent test is the low value/high system cost ratio. Applications whose value is greater than 1 in that column (area regulation, T&D upgrade deferral, and electric service power quality) are the most likely to generate profit. According to these results, locations in need of small T&D upgrades and clusters of customers which would particularly benefit from a storage device as insurance against power quality contingencies would be the best places to start deploying used EV batteries as they become available. On the other hand, applications whose high value/low system cost ratio is below 1 (electric energy time shift, voltage support, transmission congestion relief, demand charge management, and the renewables applications) would be the least promising from the perspective of a private investor.

Discount rates of 6.18% and 10% lead to somewhat different levels of the ratios but the exact same qualitative results (i.e., none of the ratios that are below 1 in Table 10.2 are above 1 for any of those two alternative discount rates and vice versa). For that reason, tables for those discount rates have not been included in this final report.

Results in Table 10.3 are similar to those in Table 10.2. Having to recover costs over a 5-year period is more demanding than doing it over 10. For that reason, every ratio which was below 1 in the previous table is even lower in this one, and some of the ratios which were above 1 when the secondary-use battery system was expected to last 10 years fell below 1 when the assumed operating life was cut in half. For example, electric supply capacity and electric supply reserve capacity no longer pass the benefit-cost ratio test anywhere in the assumed range of values and costs, and load following only displays a ratio greater than 1 under the most favorable case, high value combined with low system costs.

Area regulation, electric service power quality, and T&D upgrade deferral are still able to generate revenues well in excess of total system costs over the whole range of assumed values and costs. The first two of these have small discharge durations (15 minutes and 30 seconds, respectively), so they do not require purchasing and transporting large amounts of storage capacity, which is the most expensive element of the system. However, a large ratio of peak power to storage capacity does not guarantee an attractive value proposition.

For some applications like voltage support, the low use factor (only a few hours over the entire operating life of the system) makes it very hard to find a financial justification for it as an individual application. However, finding synergies with other applications can help making a business case for services with a low use factor. A disappointing result of the previous analysis, due to their large market potential, is that neither the energy time shift nor the renewables capacity firming applications appear as strong candidates for profitable secondary use of EV batteries. In both cases, peak vs off-peak differentials and the cost of used batteries are crucial elements whose evolution will determine whether they could generate a positive net return by 2020. Meanwhile, stacking energy time shift and capacity applications could improve the profitability potential for these large scale applications.

10.2 SYNERGISTIC BENEFITS

The preceding section shows that, on an individual basis, only a few applications make an attractive value proposition for secondary use of EV batteries over the entire range of value and cost assumptions. Moreover, demand for those applications alone will presumably not be enough to absorb the entire volume of secondary-use EV batteries predicted for 2020. Thus, investigating the extent to which the applications discussed in Sects. 5 through 9 can be combined is crucial in building a more robust business case for secondary-use battery storage.

There are several ways to aggregate benefits over the life of a used EV battery system:

- capacity of a battery system could be partitioned and each of its fractions used for different applications or
- given the modularity of battery systems, a business case might be constructed in which a system would be deployed on different locations to provide the same or different services throughout its lifetime

This report is mostly concerned with *synergies*, understood as the net benefit from using the same capacity for multiple applications at a given location. In some cases, the energy consumed/generated while charging/discharging the battery might provide multiple benefits simultaneously. Then, all those benefits could be aggregated. In other cases, battery use on one application precludes simultaneous use on another. In those cases, assumptions or simulations of how the battery system would be operated are required to determine the best scenario. To the extent that it is technically possible, the highest value application should be chosen at each point in time.

Many aspects need to be taken into account before deciding which combinations of applications are feasible:

- size (e.g., a battery storage system with discharge duration below 2 hours will be ill-suited for applications like electric energy time shift or demand charge management, which require continuous energy over longer periods),
- power-to-energy ratio (e.g., a battery storage system with a low power-to-energy ratio will not perform well in electric service reliability applications),
- duty cycle (e.g., area regulation is incompatible with most other applications because it requires continuous charging/discharging),
- operation profile (e.g., during peak load hours both energy and capacity are most valuable, so a battery system discharging at those times can be credited with both an avoided energy cost of having to use more expensive generation and an avoided cost of having to build/rent additional capacity), and
- involved stakeholders (e.g., the way in which a utility would operate a battery storage system might differ significantly from what a merchant storage operator would do; the former will view batteries as a tool to optimize operations of a broader set of assets while the latter will strictly look for profit maximization on the battery system).

When trying to determine how to dispatch a battery system that is being used for multiple applications, one possible strategy consists in deciding which one is the primary application and which ones are secondary. Based on results from the previous section, those applications with the highest individual benefits will be chosen as primary applications. Then other applications with which they would be compatible according to the above considerations will be taken as secondary applications.

Designing a versatile battery storage system which could be usable for a wide array of applications will often come with an associated cost premium. For instance, a sodium sulfur battery system used for load leveling plus T&D upgrade deferral does not need to have a fast response time, and therefore, it does not require installing expensive grid-interactive power electronics. Also, it does not experience the standby losses associated with keeping the unit always in standby condition.[43] However, should the same system provide regulation service or be used for power quality applications, it would carry with it both of those additional costs.

In the following subsections combinations which were among those highlighted in the SNL and EPRI reports[14,16] will be analyzed in detail.

10.2.1 Electric Supply Capacity Plus Electric Energy Time Shift Plus Voltage Support

Both energy and capacity from a battery system will be most valuable during peak load hours. If the battery system participates in a capacity market and receives a payment for providing its demonstrated level of net maximum dependable capacity, its available energy should be bid during peak hours. Because the assumption is that voltage support will be needed for one or two events over the life of the battery system, operational conflicts will be mostly nonexistent. However, the battery system should be strategically located in a place where voltage sags are more probable, normally within load centers. To provide voltage support, the system must also be able to inject reactive power and to respond in a time frame of seconds. Electric energy time shift and electric supply capacity do not require such capability or response times. Table 10.4 shows the benefits from combining these three applications, and Fig. 10.6 shows the benefits and costs at the discount rates discussed previously.

Table 10.4. Present value of life-cycle benefits for synergistic application 1 (electric supply capacity *plus* electric energy time shift *plus* voltage support)

Benefit category	Storage efficiency 0.7	Storage efficiency 0.8	Storage efficiency 0.9
Life-Cycle Benefit I	1,554.61	1,639.97	1,725.32
Life-Cycle Benefit II	1,403.34	1,480.17	1,556.99
Life-Cycle Benefit III	903.44	952.10	1,000.75
Life-Cycle Benefit IV	1,379.16	1,454.63	1,530.09

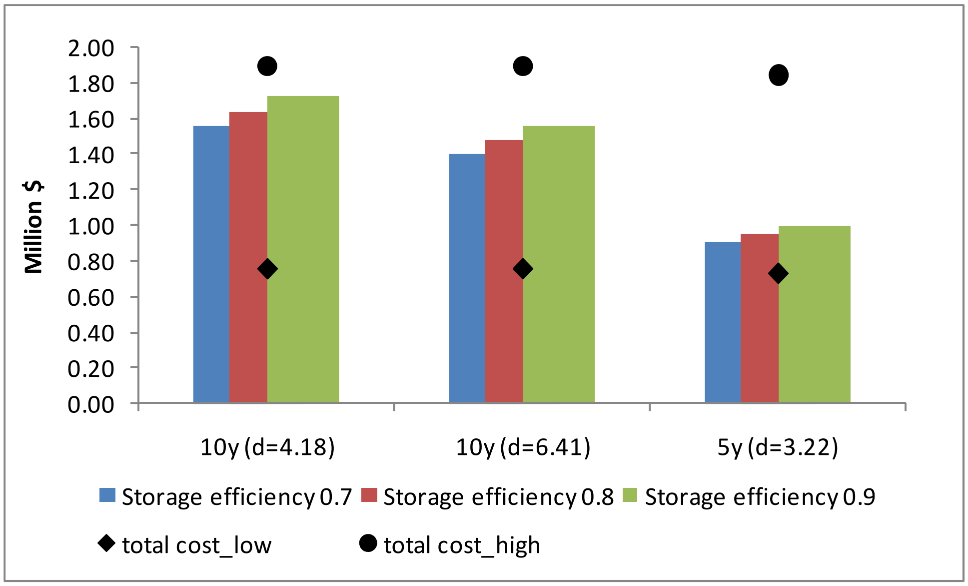


Fig. 10.6. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 1 (electric supply capacity *plus* electric energy time shift *plus* voltage support).

The PVs must now be scaled up to the size of a system that could provide all these services (1 MW of peak power and 5 MWh of energy storage capacity) and compared to the life-cycle costs of such a system to determine whether this synergistic application is attractive from a financial perspective.

For the low end of the system cost range, this synergistic application would generate more value over its lifetime than its cost of installation and maintenance for any of the discount rates and life-cycle durations considered. However, none of the combinations of storage efficiency, discount rate, and life-cycle duration generates enough revenue to cover system costs at the high end of the estimated cost range.

10.2.2 Transmission and Distribution Upgrade Deferral Plus Electric Energy Time Shift Plus Voltage Support

Both energy and capacity from a battery system installed in a transmission-constrained load pocket will have their highest values during peak load hours in that specific location. The most relevant peak and off-peak prices for a battery system designed to provide this combination of services will be the prices at that load pocket. In fact, it might be that the value proposition for such a battery system would be attractive if calculations were done based on locational marginal prices but not attractive if system-wide average prices were used instead.

Maximizing the value of a battery system designed to provide this combination of applications might imply transporting it to different points on the grid in different years. However, transporting the battery system from one location to another has a cost that was not taken into account in the system costs considered in this report. Therefore, the assumption is that the battery system stays in the same location throughout its operating life.

Table 10.5 shows the life-cycle benefits for various scenarios at three levels of storage efficiency and two transmission upgrade marginal cost levels, corresponding to the 50th and 90th percentile of the marginal costs for California. A conversion factor of 0.8 was used to translate benefits expressed in dollars per kilovolt-ampere years in Sect. 7.3 into dollars per kilowatt-years.

Table 10.5. Life-cycle benefits in synergistic application 2 (transmission and distribution upgrade deferral *plus* electric energy time shift *plus* voltage support)

Benefit category ($/kW)	Storage efficiency 0.7	Storage efficiency 0.8	Storage efficiency 0.9
	50th percentile ($420/kW)		
Life-Cycle Benefit I	7,495.46	7,580.82	7,666.17
Life-Cycle Benefit II	6,748.84	6,825.67	6,902.49
Life-Cycle Benefit III	4,281.56	4,330.22	4,378.87
Life-Cycle Benefit IV	6,629.52	6,704.98	6,780.45
	90th percentile ($662/kW)		
Life-Cycle Benefit I	11,499.77	11,585.13	11,670.48
Life-Cycle Benefit II	10,353.21	10,430.04	10,506.87
Life-Cycle Benefit III	6,564.31	6,612.97	6,661.63
Life-Cycle Benefit IV	10,169.97	10,245.44	10,320.91

The values in Table 10.6 assume that the T&D upgrade deferral benefit applies to the entire operating life of the battery system. However, it could be that new transmission infrastructure is built at some point during the life of the battery system. In that case, the value from that application should only be counted up until the year in which the upgrade in transmission or distribution capacity comes online.

Table 10.6. Life-cycle benefits in synergistic application 3 [transmission and distribution (T&D) upgrade deferral *plus* electric supply capacity *plus* voltage support]

	50th percentile marginal cost of T&D upgrade= $420/kW	90th percentile marginal cost of T&D upgrade= $662/kW
Life-Cycle Benefit I	7,927.25	11,931.56
Life-Cycle Benefit II	7,137.50	10,741.88
Life-Cycle Benefit III	4,527.71	6,810.46
Life-Cycle Benefit IV	7,011.29	10,551.74

Figure 10.7 compares the life-cycle value and costs of a battery system sized to provide these three services. The assumed size is the largest of the three described for the individual applications (1 MW peak power and 5 MWh storage duration). The assumed marginal cost of T&D upgrades corresponds to the 50th percentile.

This synergistic application clearly shows an attractive business case. Its life-cycle benefits for every life-cycle duration, discount rate, and storage efficiency are at least double the highest assumed system costs. The biggest fraction of the value comes from the T&D upgrade deferral application so that storage efficiency, mostly relevant for energy time-shift applications, barely makes a difference. Amortization of the costs associated with this application would happen even faster if the system were installed at a location where the marginal cost of installed T&D upgrades is above the 90th percentile value.

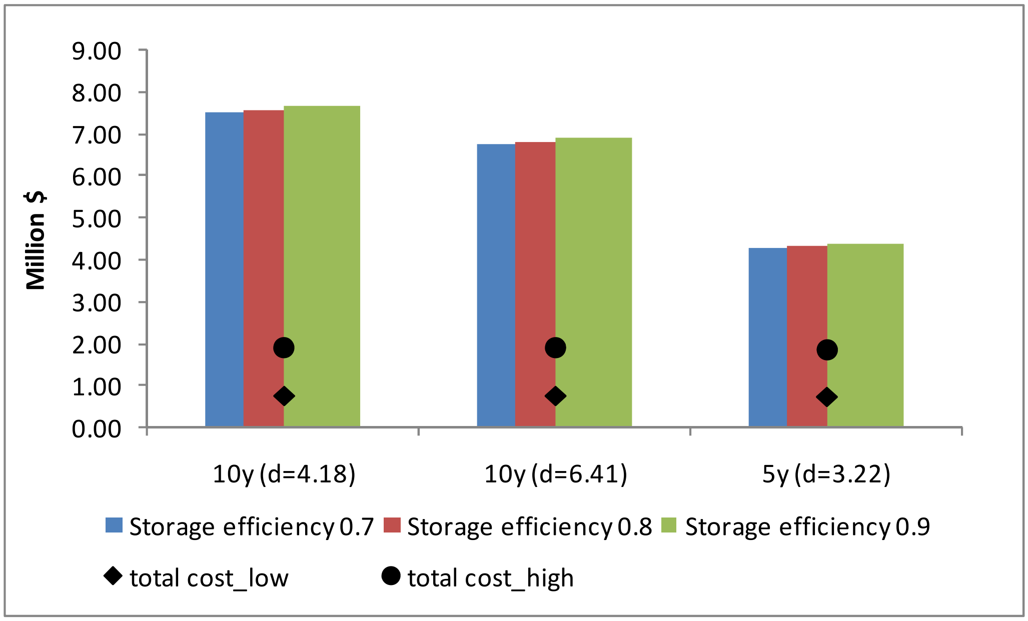


Fig. 10.7. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 2 (T&D upgrade deferral *plus* energy time shift *plus* voltage support).

10.2.3 Transmission and Distribution Upgrade Deferral Plus Electric Supply Capacity Plus Voltage Support

This combination of applications, whose life-cycle PV benefits are summarized in Table 10.6, could be attractive although it is also highly location specific. It would work in a load pocket where demand is outpacing existing installed capacity for both generation and transmission of energy to end users. As in the previous synergistic application, the assumption is that the battery system is stationary and that the values from its multiple applications are sustained throughout its entire operating life.

As in the previous synergistic application, having T&D upgrade deferral as one of the services in this combined application leads to a very large life-cycle benefit relative to the cost of installing and maintaining the battery system. The life-cycle benefit-cost comparison is shown in Fig. 10.8. The assumed system size for this synergistic application is 1 MW of peak power and 4 MWh of energy storage capacity.

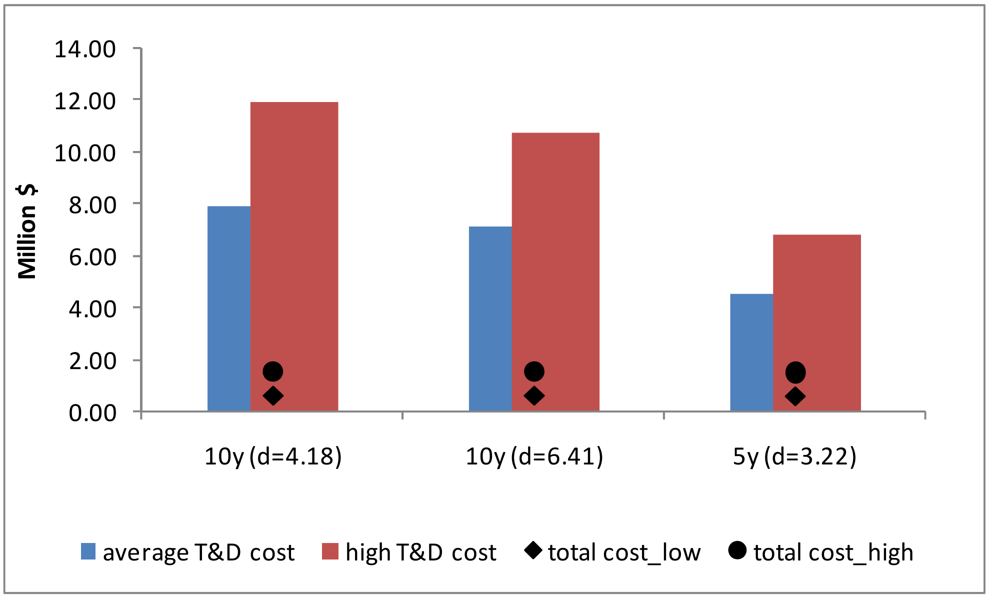


Fig. 10.8. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 3 (T&D upgrade deferral *plus* electric supply capacity *plus* voltage support).

10.2.4 Load Following Plus Electric Supply Reserve Capacity

Both these uses require operating at partial load most of the time. This feature makes the two applications compatible but might result in efficiency losses relative to a system that is charged and discharged at its peak power rate. Both these applications could be provided simultaneously most of the time. To bid capacity in the spinning reserve market, the battery must be at partial load, and that will be precisely its mode of operation for most of the morning ramp-up and evening ramp-down periods during which load following would most likely be provided. For a fraction of hours during the year reserve capacity will actually be called by the ISO or balancing authority to increase or decrease output. Reserves are called to actually produce or absorb energy in response to a contingency in the system (e.g., unplanned outage of a generation unit or transmission outage).

If the hours during which contingencies take place coincide with hours during which the battery would otherwise be providing load following, it would have to stop doing so. The North American Electric Reliability Corporation keeps track of generation outages through its Generating Availability Data System. Depending on the type of generation unit, forced outage rates range from 2% to 5%. In any given system, the forced outage rate would be within those two values depending on its particular generation mix. For transmission availability, a forced outage rate of 1% will be assumed, based on Firooz.[44] Adding up these two rates, the number of hours in which a contingency takes place would range between 263 (3%) and 526 (6%). Contingencies are assumed to be spread uniformly throughout the 24 hours of any given day. The life-cycle benefits from combining load following and supply reserve capacity for low and high contingency counts are summarized in Table 10.7.

Table 10.7. Life-cycle benefits for synergistic application 4 (load following *plus* electric supply reserve capacity)

Benefit category	Low ($/kW)	High ($/kW)
	500 hours	
Life-Cycle Benefit I	624.53	1,413.95
Life-Cycle Benefit II	562.16	1,272.73
Life-Cycle Benefit III	356.03	806.05
Life-Cycle Benefit IV	552.19	1,250.16
	1,000 hours	
Life-Cycle Benefit I	698.53	1,598.94
Life-Cycle Benefit II	628.76	1,439.24
Life-Cycle Benefit III	398.21	911.51
Life-Cycle Benefit IV	617.61	1,413.72
	2,000 hours	
Life-Cycle Benefit I	853.63	1,986.67
Life-Cycle Benefit II	768.37	1,788.25
Life-Cycle Benefit III	486.63	1,132.55
Life-Cycle Benefit IV	754.74	1,756.54

The low value case assumes a capacity factor of 0.3 for the reserves application, a price of $20/MWh for the energy substituted by the battery in its load following duty, a price of $60/kW-year for the capacity avoided by having a battery system, and a high number of contingencies. The high value case assumes a capacity factor of 0.6 for the reserves application, a price of $50/MWh for the energy substituted by the battery in its load following duty, a price of $120/kW-year for the capacity avoided by having a battery system, and a low number of contingencies.

Figures 10.9 and 10.10 compare life-cycle benefits and costs for the high and low value cases respectively. The assumed size for this battery system is 50 MW peak power and 50 MWh energy storage capacity. However, since the assumed typical size for the load following application is 1 MW peak power and 3 MWh energy storage capacity, the load following value is computed only for that power rating.

Only a combination of the high value case life-cycle benefits, low system costs, and operating life of 10 years makes this scenario profitable.

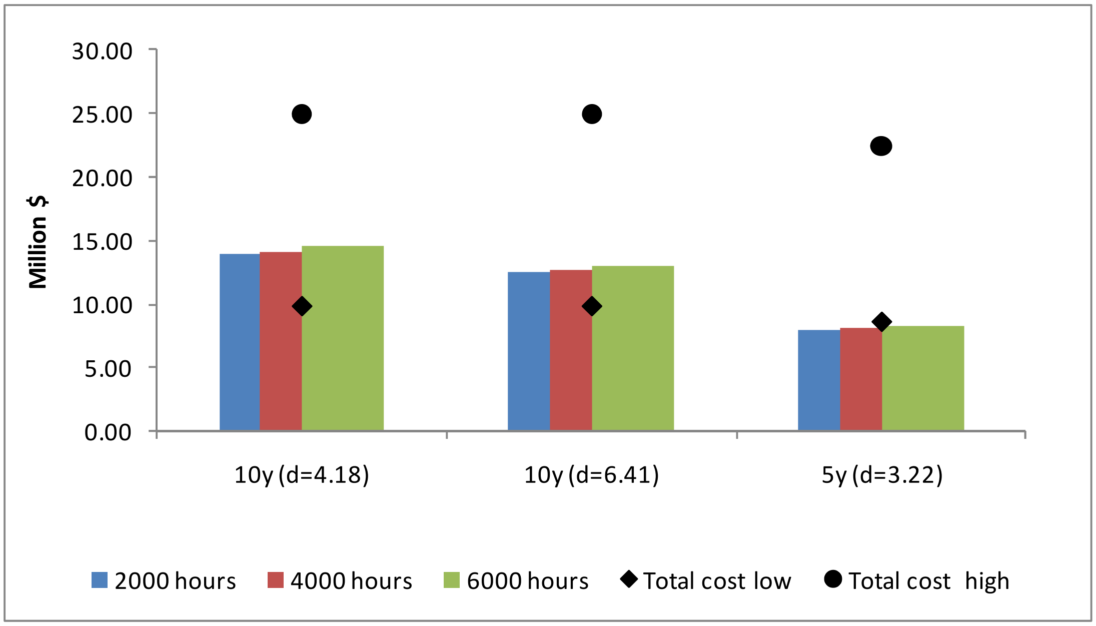


Fig. 10.9. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 4 (load following *plus* electric supply reserve capacity), high value case.

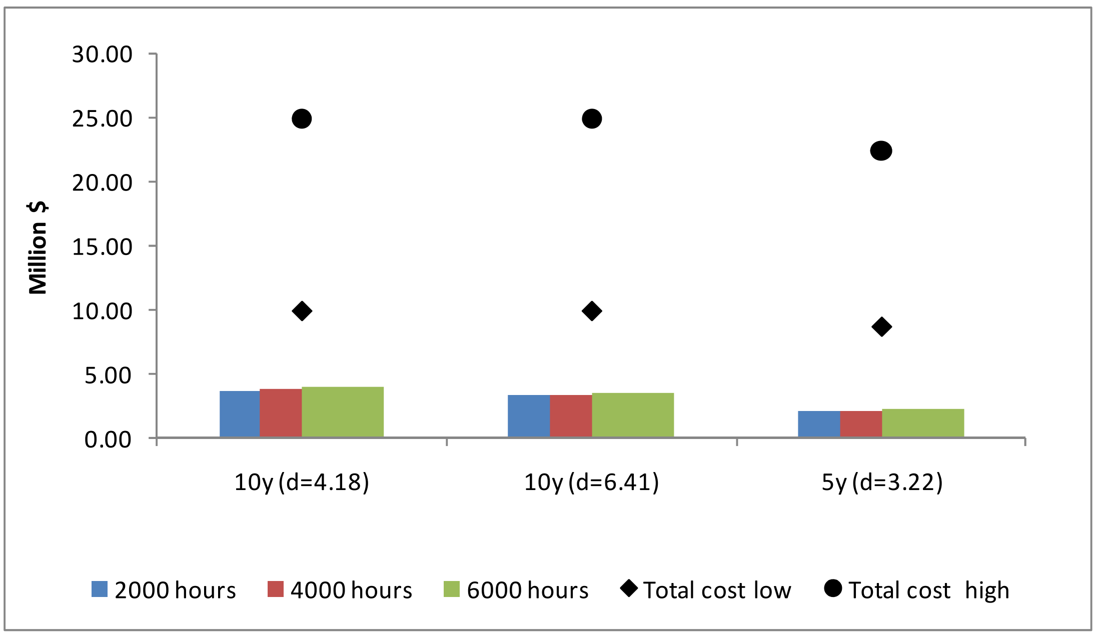


Fig. 10.10. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 4 (load following *plus* electric supply reserve capacity), low value case.

10.2.5 Time-of-Use Energy Cost Management Plus Electric Service Reliability Plus Electric Service Power Quality

A battery system primarily used for TOU energy cost management could also help customers in responding to outages and power quality events. Under PG&E's tariff A-6, used as an example for TOU energy cost management, peak rates are only applied to the summer period (May 1 through October 31). During that half of the year, the battery would be charged during off-peak hours (9:30 pm to 8:30 am) and discharged during peak hours (12:00 pm to 6:00 pm). In those hours in which an event happens, the usual charge/discharge cycle is disrupted and the battery cannot perform its energy shift duty. The difference between day and night rates under this tariff during the winter months is too small to compensate for the round-trip efficiency losses involved in operating battery storage. Thus, from November 1 to April 30, except during event hours during that period, the battery could be used for another application and/or another customer. This is a case where maximizing the value of the battery could involve use by multiple customers. It is conceivable that an aggregator would act as coordinator of multiple customers to optimize the value of the battery device.

Table 10.8 displays the life-cycle benefit of combining these three applications assuming that half of the outages (i.e., 1.25/year) and half of the power quality events (i.e., 5/year) happen during the summer season for which peak rates apply in the examined tariff (PG&E A-6).

Table 10.8. Life-cycle benefits for synergistic application 5 (time-of-use energy management *plus* electric service reliability *plus* electric service power quality)

Benefit category	Low	High
Life-Cycle Benefit I	1,895.15	2,097.90
Life-Cycle Benefit II	1,705.87	1,888.37
Life-Cycle Benefit III	1,080.38	1,195.96
Life-Cycle Benefit IV	1,675.62	1,854.89

This combination of applications could be undertaken by small residential customers or larger C&I customers. Typical sizes for battery systems installed by those two types of customers and capable of providing this array of services would be 1 kW peak power with 4 kWh of storage capacity for the residential type and 10 MW peak power with 4MWh of storage capacity for the C&I type. The comparison between life-cycle benefits and costs for those two system sizes is presented in Figs. 10.11 and 10.12. It should be noted that values in Fig. 10.11 are in dollars rather than millions of dollars.

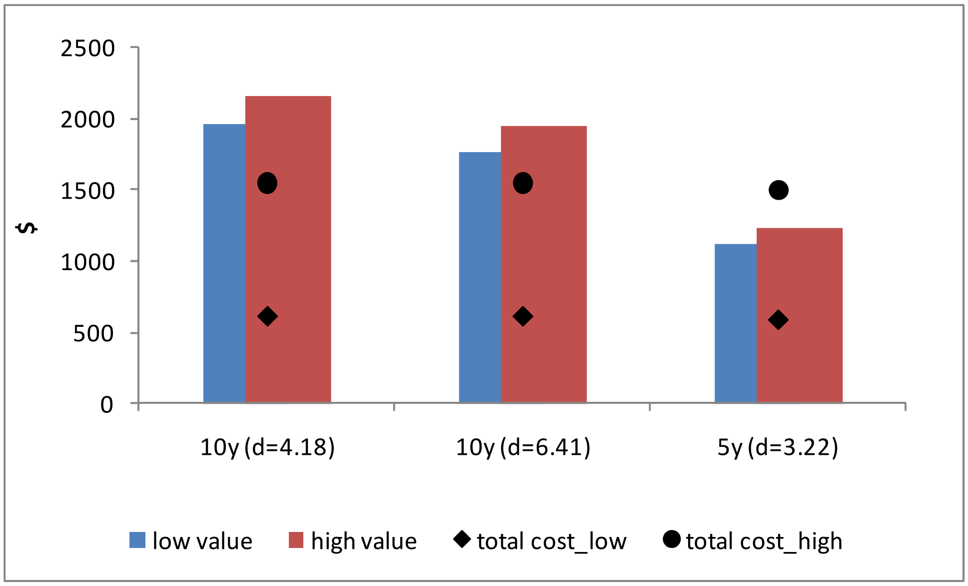


Fig. 10.11. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 5 (time-of-use energy management *plus* electric service reliability *plus* electric service power quality), residential scale.

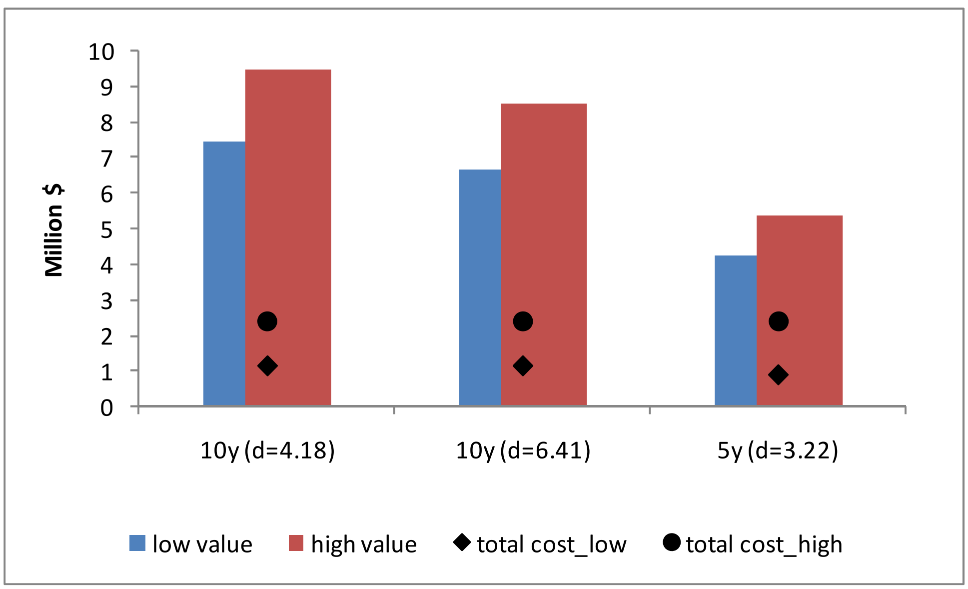


Fig. 10.12. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 5 (time-of-use energy management *plus* electric service reliability *plus* electric service power quality), commercial and industrial scale.

Stacking these applications looks like a sound financial choice for both types of customers but clearly more so for C&I customers. Life-cycle costs are driving this difference. The main cost components (cost of used batteries and transportation costs) are expressed in dollars per kilowatt-hour so that battery systems with lower peak power to storage capacity ratios are going to be more expensive overall.

10.2.6 Demand Charge Management (Summer) Plus Electric Service Reliability Plus Electric Service Power Quality

A battery system primarily used for demand charge management could also help customers in responding to outages and power quality events. The electric tariff used as an example to value the demand charge management is PG&E E-19. Under this tariff, peak demand charges apply only to 765 hours during the summer period. In those hours in which a reliability or quality event takes place, the usual charge/discharge cycle would be disrupted and demand charges would be incurred. As in the previous synergistic application, another use should be found for the battery device during the winter months. A possibility to explore, not included in this valuation exercise, would be continuing a similar charge/discharge cycle during the winter but selling energy to the wholesale market because the intraday price differential is more pronounced at the wholesale level than what is reflected in the customer rates for those months. Table 10.9 presents the outcome from combining the values of these three customer applications.

Table 10.9. Life-cycle benefits of synergistic application 6 (demand charge management *plus* electric service reliability *plus* electric service power quality)

Benefit category	Low	High
Life-Cycle Benefit I	1,209.56	1,412.31
Life-Cycle Benefit II	1,088.76	1,271.26
Life-Cycle Benefit III	689.54	805.12
Life-Cycle Benefit IV	1,069.45	1,248.71

This combination of applications is only relevant for C&I customers. Figure 10.13 shows the comparison between life-cycle benefits and costs for this scenario. The assumed system size is 10 MW peak power and 1.67 MW storage capacity.

The high peak power to storage capacity ratio makes for relatively low system costs. Under the assumptions in this analysis, this combination would make sense from a financial perspective even for an operating life of only 5 years and even for high unit costs for every megawatt installed.

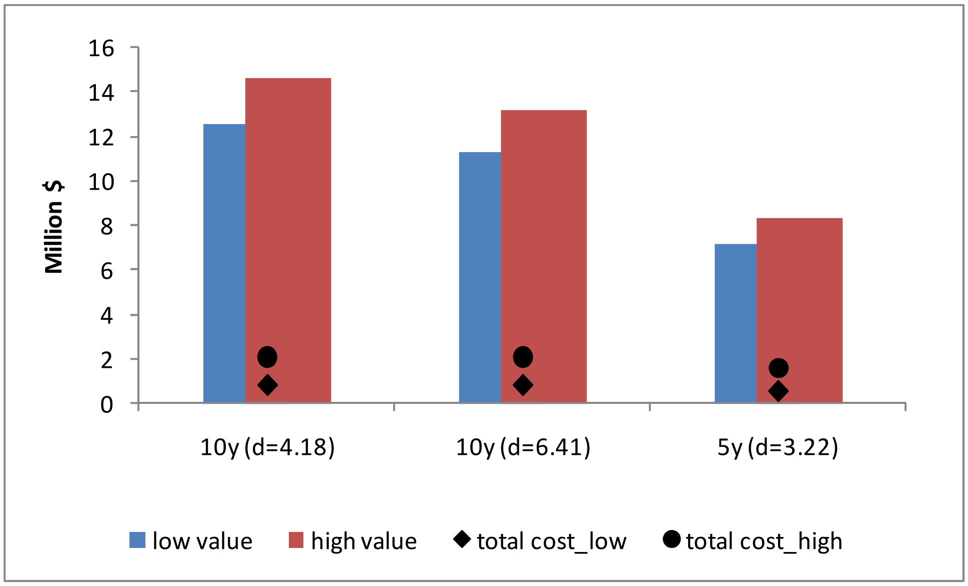


Fig. 10.13. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 6 (demand charge management *plus* electric service reliability *plus* electric service power quality), commercial and industrial scale.

10.2.7 Renewables Energy Time Shift Plus Renewables Capacity Firming

The life-cycle benefits discussed here would correspond to a battery system located in the vicinity of a wind farm. Energy time shift where the battery system is charged using energy generated by the wind turbines during off-peak periods would help managing wind generation variability. Moreover, the capacity firming provided by a battery system would be a good tool, from a systems operation perspective, to manage wind generation volatility. Given the large amounts of wind energy projected to come online between now and 2020 (11.5 GW according to the reference case of the 2011 *Annual Energy Outlook*), there could be a large market potential for secondary use of EV batteries under these applications.

Table 10.10 shows the life-cycle benefits for this application under two scenarios, a 5-hour and a 3-hour time shift. The first case assumes that all the generation from the wind turbines would happen during off-peak hours while the second case assumes that the wind turbines generate during 2 hours corresponding to the peak period. Both cases assume 85% storage efficiency. While the values presented in Sect. 9.2 for renewables capacity firming have a capacity and an energy component, here only the capacity component is considered (the energy component corresponds to the time-shift application).

Table 10.10. Life-cycle benefits of synergistic application 7 (renewables energy time shift *plus* renewables capacity firming)

Benefit category	5-hour time shift	3-hour time shift
Life-Cycle Benefit I	1,170.06	993.99
Life-Cycle Benefit II	1,053.20	894.72
Life-Cycle Benefit III	667.02	566.65
Life-Cycle Benefit IV	1,034.52	878.85

The assumed size for a utility-level system expected to provide these two services would be 4 MW of peak power and 20 MW of energy storage capacity so that it can time shift continuously during 5 hours when needed. (That is larger than the size used in the calculations to construct the life-cycle benefit-cost comparison in Fig. 10.14).

The net life-cycle benefit of a battery system performing energy time shift and capacity firming services for a nearby wind farm would only be positive at the lower end of the assumed system cost range and with a 10-year operating life.

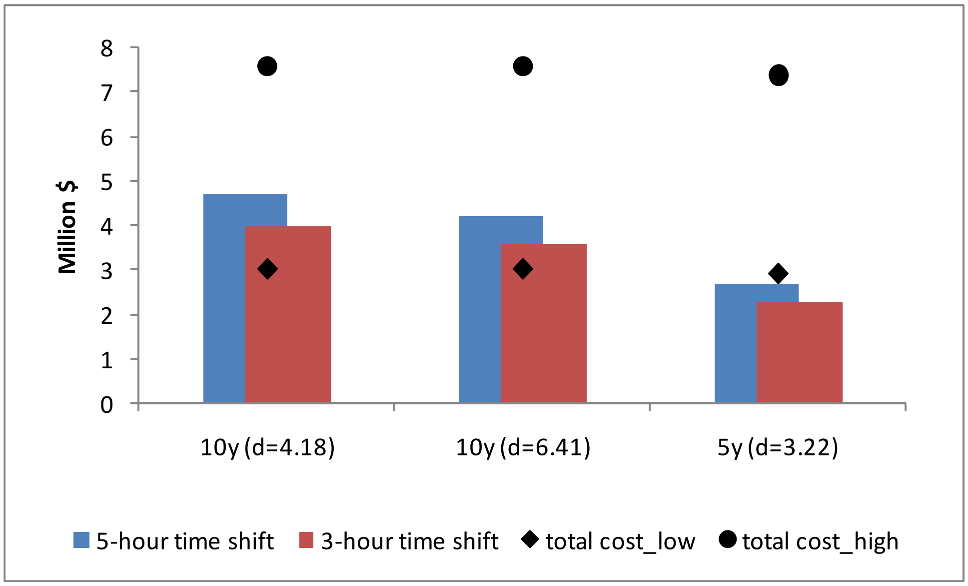


Fig. 10.14. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 7 (renewables energy time shift *plus* renewables capacity firming).

10.2.8 Community Energy Storage

CES systems are relatively small (25 kW with 1- to 3-hour backup) battery energy storage systems that are deployed in neighborhoods either on street corners or along backyard utility rights-of-way. These units exist between the transformer that steps down the distribution level voltage to 240 V/120 V and homes. In this location, the CES units can provide multiple benefits that have already been defined including electric energy time shift, ancillary services, T&D capital deferral, voltage support, service reliability, TOU energy cost management, and firming and shifting of renewables. More specifically, the CES is able to supply the following services.

1. Electric energy time shift: On an aggregated scale, the energy storage units can store energy at night created by excess generation and deliver this energy during peak periods to homes.

2. Ancillary service applications: The CES provides a buffer between the residential load variability and the utility through flattening the load profile. On an aggregated scale this reduces the need for ancillary services and capturing the imbalance of generation and load in real time.

3. T&D upgrade deferral: The transformer delivering power to homes potentially needs upgrading with the addition of PHEVs and expected load increases. However, this upgrade could be mitigated with a CES unit. On an aggregated scale, this holds true as well to the substation transformer.

4. Voltage support: The internal inverter that interconnects the low voltage AC to the DC bus for the batteries can be controlled to dynamically provide reactive power support and adjust power factor.

5. Service reliability: With several hours of backup power and a disconnection switch, the CES is able to continue providing power to the homes in islanding mode during utility outage.

6. TOU energy cost management: The utility owner is able to benefit from high TOU rates as the load profile has been flattened.

7. Firming and shifting renewables: The CES is able to behave as a buffer between the utility and renewables (solar photovoltaic panels installed in roofs) by absorbing excess energy from the renewables and delivering energy during periods of shortage.

In the analysis of CES benefits from a utility perspective, time shifting, T&D upgrade deferral, TOU energy cost management, and renewable capacity firming are considered. The TOU energy cost management benefit for the utility makes reference to the fact that, without battery storage, the high tariff charged to customers during peak hours goes towards buying expensive peak energy in the market or having to dispatch expensive peaking plants. If the utility continues charging TOU rates but draws peak energy from battery storage, its net revenue will increase. Although inherent benefit of the CES units would be the reduced need for regulation and an increased reliability to residential customers, the utility does not directly sell regulation or voltage support to an ISO with these units or sell the reliability service to residential customers.

The combined annual benefit from energy time shifting plus T&D upgrade deferral plus renewable capacity firming would be in the 1,200–1,700 $/kW range. Table 10.11 presents the lifecycle benefits under this application.

Table 10.11. Life-cycle benefits of synergistic application 8 (community energy storage)

Benefit category	Low ($/kW)	High($/kW)
Life-Cycle Benefit I	9,562.97	13,738.00
Life-Cycle Benefit II	8,607.86	12,365.89
Life-Cycle Benefit III	5,451.59	7,831.66
Life-Cycle Benefit IV	8,455.21	12,146.61

The total cost of installing a CES battery system with a power rating of 25 kWh and 3-hour discharge duration would range between $11,000 and $27,000. Thus, installation cost would be paid off in the first year. Because the largest fraction of value comes from the T&D upgrade deferral application, communities that would otherwise need transformer upgrades would initially be the most attractive. Communities where intermittent renewables are installed would also be good candidates. In any case, the value proposition for CES applications remains profitable even under pessimistic assumptions. The benefit-cost ratio in the low value-high cost case is 7.07 (Fig. 10.15).

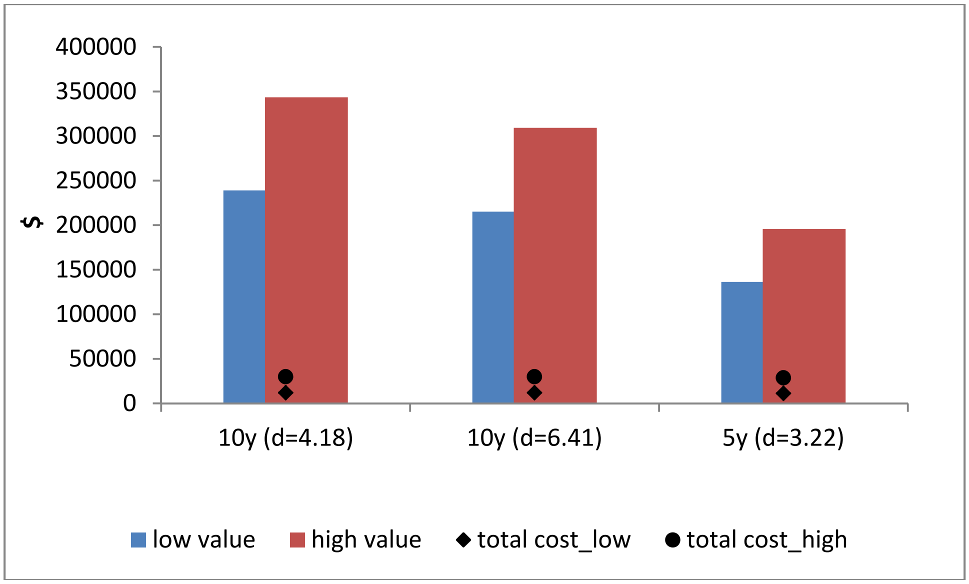


Fig. 10.15. Comparison of life-cycle benefits and costs at various discount rates (d) for synergistic application 8 (community energy storage, utility benefits).

11. RECOMMENDATIONS

This initial scoping study presents a comprehensive approach for evaluation of secondary-use battery market. Based on the work presented in this report, we suggest the following activities to facilitate the decision making process related to commercialization of secondary-use batteries.

1. Develop a comprehensive mathematical model which can be used in the decision making process.

2. Incorporate the impact of proposed and emerging policies that can impact the secondary-use battery market.

3. Validate assumptions, benefits, and feasibility through comprehensive testing of secondary-use batteries on the grid.

4. Demonstrate feasibility in a commercial application.

While mathematical modeling will be quite helpful in the decision making process, the impact of experimental data summarizing the performance and residual battery life in a given grid application will be invaluable. The lack of such data forces us to assume a 5- or 10-year residual life of secondary-use batteries. Furthermore, we are assuming that secondary-use batteries can be effectively used for a variety of grid applications. However, the decision tool used only analyzed financial benefits and ignored benefits to the environment and to society because such benefits are impossible to estimate in the absence of actual experimental data. Because of this, we suggest initiating comprehensive testing of secondary-use batteries to provide input to the decision tool being developed at Oak Ridge National Laboratory for commercialization of secondary-use batteries.

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APPENDIX A: DOT: 49 CFR, 173.185(D)

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TITLE 49 – TRANSPORTATION

SUBTITLE B - OTHER REGULATIONS RELATING TO TRANSPORTATION

CHAPTER I - PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION, DEPARTMENT OF TRANSPORTATION

SUBCHAPTER C - HAZARDOUS MATERIALS REGULATIONS

PART 173 - SHIPPERS - GENERAL REQUIREMENTS FOR SHIPMENTS AND PACKAGINGS

subpart e - NON - BULK PACKAGING FOR HAZARDOUS MATERIALS OTHER THAN CLASS 1 AND CLASS 7

173.185 - Lithium batteries and cells.

(a) Except as otherwise provided in this subpart, a lithium cell or battery is authorized for transportation only if it conforms to the provisions of this section. For the purposes of this subchapter, lithium content means the mass of lithium in the anode of a lithium metal or lithium alloy cell, except in the case of a lithium ion cell where the equivalent lithium content in grams is calculated to be 0.3 times the rated capacity in ampere-hours. The lithium-equivalent content of a battery equals the sum of the grams of lithium-equivalent content contained in the component cells of the battery.

(b) Exceptions. Except for primary (non-rechargeable) lithium batteries and cells transported aboard passenger-carrying aircraft, cells and batteries are not subject to any other requirements of this subchapter if they meet the following: (1) Each cell with a liquid cathode may contain not more than 0.5 g of lithium content. Each cell with a solid cathode may contain not more than 1.0 g of lithium content. Each lithium ion cell may contain not more than 1.5 g of equivalent lithium content; (2) Each battery with a liquid cathode may contain an aggregate quantity of not more than 1.0 g of lithium content. Each battery with a solid cathode may contain an aggregate quantity of not more than 2.0 g of lithium content. Each lithium-ion battery may contain an aggregate quantity of not more than 8.0 grams of equivalent lithium content; (3) Each cell or battery containing a liquid cathode must be hermetically sealed; (4) Cells and batteries must be packed in such a way so as to prevent short circuits and must be packed in strong packagings, except when installed in equipment; and (5) The outside of each package that contains a primary (non-rechargeable) lithium battery or cell must be marked PRIMARY LITHIUM BATTERIESFORBIDDEN FOR TRANSPORT ABOARD PASSENGER AIRCRAFT on a background of contrasting color, in letters: (i) At least 12 mm (0.5 inch) in height on packages having a gross mass of more than 30 kg (66 pounds); or (ii) At least 6 mm (0.25 inch) on packages having a gross mass of 30 kg (66 pounds) or less; and (6) If when fully charged, the aggregate lithium content of the anodes in a liquid cathode battery is more than 0.5 g, or the aggregate lithium content of the anodes in a solid cathode battery is more than 1.0 g, then the battery may not contain a liquid or gas that is a hazardous material according to this subchapter unless the liquid or gas, if free, would be completely absorbed or neutralized by other materials in the battery.

(c) Except for primary lithium (non-rechargeable) batteries and cells transported aboard passenger-carrying aircraft, cells and batteries are not subject to any other requirements of this subchapter if they meet the following: (1) The lithium content of the anode of each cell, when fully charged, is not more than 5 g; (2) The aggregate lithium content of the anodes of each battery, when fully charged, is not more than 25 g; (3) Each cell or battery is of the type proven to be non-dangerous by testing in accordance with

Tests in the UN Manual of Tests and Criteria (IBR; see 171.7 of this subchapter). Such testing must be carried out on each type of cell or battery prior to the initial transport of that type. A cell or battery and equipment containing a cell or battery which was first transported prior to January 1, 2006 and is of a type proven to meet the criteria of Class 9 by testing in accordance with the tests in the UN Manual of Tests and Criteria, Third Revised Edition, 1999 is not required to be retested; (4) The outside of each package that contains a primary (non-rechargeable) lithium battery or cell must be marked PRIMARY LITHIUM BATTERIESFORBIDDEN FOR TRANSPORT ABOARD PASSENGER AIRCRAFT on a background of contrasting color, in letters: (i) At least 12 mm (0.5 inch) in height on packages having a gross mass of more than 30 kg (66 pounds); or (ii) At least 6 mm (0.25 inch) on packages having a gross mass of 30 kg (66 pounds) or less; and (5) Cells and batteries are designed or packed in such a way as to prevent short circuits under conditions normally encountered in transportation.

(d) Except for transportation aboard passenger-carrying aircraft, cells and batteries and equipment containing cells and batteries that were first transported prior to January 1, 1995, and were assigned to Class 9 on the basis of the requirements of this subchapter in effect on October 1, 1993, may continue to be transported in accordance with the applicable requirements in effect on October 1, 1993.

(e) Cells and batteries may be transported as items of Class 9 if they meet the requirements in paragraphs (e)(1) through (e)(7) of this section: (1) Each cell and battery must be equipped with an effective means of preventing external short circuits.

(2) Each cell and battery must incorporate a safety venting device or be designed in a manner that will preclude a violent rupture under conditions normally incidental to transportation.

(3) Batteries containing cells or series of cells connected in parallel must be equipped with effective means, (such as diodes, fuses, etc.) as necessary to prevent dangerous reverse current flow.

(4) Authorized outer packagings: rigid outer packagings that conform to the general packaging requirements of part 173 and the packaging specification and performance requirements of part 178 of this subchapter at the Packing Group II performance level. Cells and batteries must be packed in such a manner as to effectively prevent short circuits through the use of inner packagings, dividers, or other suitable means.

(5) [Reserved] (6) Each cell or battery is of the type proven to meet the lithium battery requirements in the UN Manual of Tests and Criteria (IBR; see 171.7 of this subchapter). A cell or battery and equipment containing a cell or battery of a design type which was first transported prior to January 1, 2006 and is of a type proven to meet the criteria of Class 9 by testing in accordance with the tests in the UN Manual of Tests and Criteria, Third Revised Edition, 1999 is not required to be retested; (7) Except as provided in paragraph (h) of this section, cells and batteries with a liquid cathode containing sulfur dioxide, sulfuryl chloride or thionyl chloride may not be offered for transportation or transported if any cell has been discharged to the extent that the open circuit voltage is less than two volts, or is less than two-thirds of the voltage of the fully charged cell, whichever is less.

(f) Equipment containing or packed with cells and batteries meeting the requirements of paragraph (b) or (c) of this section is excepted from all other requirements of this subchapter.

(g) Equipment containing or packed with cells and batteries may be transported as items of Class 9 if the batteries and cells meet all requirements of paragraph (e) of this section and are packaged as follows: (1) Equipment containing cells and batteries must be packed in a strong outer packaging that is waterproof or has a waterproof liner, unless the equipment is made waterproof by nature of its construction. The equipment must be secured within the outer packaging and be packed as to effectively prevent moving, short circuits, and accidental operation during transport; and (2) Cells and batteries packed with equipment must be packed in inner packagings conforming to (e)(4) of this section in such a manner as to effectively prevent moving and short circuits.

(h) Cells and batteries, for disposal, may be offered for transportation or transported to a permitted storage facility and disposal site by motor vehicle when they meet the following requirements: (1) Be equipped with an effective means of preventing external short circuits; and (2) Be packed in a strong outer packaging conforming to the requirements of 173.24 and 173.24a. The packaging need not conform to performance requirements of part 178 of this subchapter.

(i) Cells and batteries and equipment containing or packed with cells and batteries which do not comply with the provisions of this section may be transported only if they are approved by the Associate Administrator.

(j) For testing purposes, when not contained in equipment, cells and batteries may be offered for transportation or transported by highway as items of Class 9. Packaging must conform with paragraph (e)(4) of this section.

(k) Batteries employing a strong, impact-resistant outer casing and exceeding a gross mass of 12 kg (26.5 lbs.), and assemblies of such batteries, may be packed in strong outer packagings, in protective enclosures (for example, in fully enclosed wooden slatted crates) or on pallets. Batteries must be secured to prevent inadvertent movement, and the terminals may not support the weight of other superimposed elements.

Batteries packaged in this manner are not permitted for transportation by passenger aircraft, and may be transported by cargo aircraft only if approved by the Associate Administrator prior to transportation.

[66 FR 8647, Feb. 1, 2001; 66 FR 33430, June 21, 2001, as amended at 66 FR 45379, Aug. 28, 2001; 67 FR 15743, Apr. 3, 2002; 68 FR 45034, July 31, 2003; 68 FR 75742, Dec. 31, 2003; 69 FR 34611, June 22, 2004; 69 FR 54046, Sept. 7, 2004; 69 FR 75216, Dec. 15, 2004; 69 FR 76157, Dec. 20, 2004; 68 FR 61941, Oct. 30, 2003; 70 FR 34398, June 14, 2005] Editorial Note: At 68 FR 61941, Oct. 30, 2003, 173.185 was amended; however, a portion of the amendment could not be incorporated due to inaccurate amendatory instruction.