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

Final Report 07-06
Volume II: Appendices
March 2007

New York State
Energy Research and
Development Authority

The New York State Energy Research and Development Authority (NYSERDA) is a public benefit corporation created in 1975 by the New York State Legislature. NYSERDA's responsibilities include:

- Conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs.
- Administering the **New York Energy $mart**SM program, a Statewide public benefit R&D, energy efficiency, and environmental protection program.
- Making energy more affordable for residential and low-income households.
- Helping industries, schools, hospitals, municipalities, not-for-profits, and the residential sector, including low-income residents, implement energy-efficiency measures.
- Providing objective, credible, and useful energy analysis and planning to guide decisions made by major energy stakeholders in the private and public sectors.
- Managing the Western New York Nuclear Service Center at West Valley, including: (1) overseeing the State's interests and share of costs at the West Valley Demonstration Project, a federal/State radioactive waste clean-up effort, and (2) managing wastes and maintaining facilities at the shut-down State-Licensed Disposal Area.
- Coordinating the State's activities on energy emergencies and nuclear regulatory matters, and monitoring low-level radioactive waste generation and management in the State.
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NYSERDA administers the **New York Energy $mart**SM program, which is designed to support certain public benefit programs during the transition to a more competitive electricity market. Some 2,700 projects in 40 programs are funded by a charge on the electricity transmitted and distributed by the State's investor-owned utilities. The **New York Energy $mart**SM program provides energy efficiency services, including those directed at the low-income sector, research and development, and environmental protection activities.

NYSERDA derives its basic research revenues from an assessment on the intrastate sales of New York State's investor-owned electric and gas utilities, and voluntary annual contributions by the New York Power Authority and the Long Island Power Authority. Additional research dollars come from limited corporate funds. Some 400 NYSERDA research projects help the State's businesses and municipalities with their energy and environmental problems. Since 1990, NYSERDA has successfully developed and brought into use more than 170 innovative, energy-efficient, and environmentally beneficial products, processes, and services. These contributions to the State's economic growth and environmental protection are made at a cost of about $.70 per New York resident per year.

Federally funded, the Energy Efficiency Services program is working with more than 540 businesses, schools, and municipalities to identify existing technologies and equipment to reduce their energy costs.

For more information, contact the Communications unit, NYSERDA, 17 Columbia Circle, Albany, New York 12203-6399; toll-free 1-866-NYSERDA, locally (518) 862-1090, ext. 3250; or on the web at www.nyserda.org

GUIDE TO ESTIMATING BENEFITS AND MARKET POTENTIAL FOR ELECTRICITY STORAGE IN NEW YORK (WITH EMPHASIS ON NEW YORK CITY)

FINAL REPORT

VOLUME II: APPENDICES

Prepared for the

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

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Appendices

Appendix A. Information, Reports, Manuals and Web Links

United States Department of Energy, Office of (OE)

Home Page
http://www.electricity.doe.gov

R&D Group (includes energy storage)
http://www.electricity.doe.gov/electric.cfm

Energy Storage Association

Home Page
http://www.electricitystorage.org/about.htm

Power Quality and Delivery
http://www.electricitystorage.org/

Storage Technology
http://www.electricitystorage.org/technologies.htm

Sandia National Laboratories Energy Storage Program

Home Page
http://www.sandia.gov/ess/

NYSERDA

Home Page
http://www.nyserda.org/

Study Report: The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations; Phase 2, System Performance Evaluation
http://www.nyserda.org/publications/wind_integration_report.pdf

This report is perhaps *the* definitive resource for understanding wind generation operational implications for the New York Power Systems. It also addresses wind resources.

New York State Reliability Council (NYSRC)

Home Page
http://www.nysrc.org/

New York Independent System Operator (NYISO)

NYISO FAQs
http://www.nyiso.com/public/services/customer_relations/faqs/index.jsp

NYISO Documents Web Page
http://www.nyiso.com/public/documents/

NYISO Tariffs
http://www.nyiso.com/public/documents/tariffs/market_services.jsp

NYISO Market Price Data
http://www.nyiso.com/public/market_data/pricing_data.jsp

Historic and current price data for LBMP and Ancillary Services.

NYISO "User Training Manuals"
http://www.nyiso.com/public/services/market_training/online_resources.jsp

NYISO Market Participant User's Guide
http://www.nyiso.com/public/webdocs/documents/guides/mpug_mnl.pdf

This Guide provides Market Participants with the information needed to participate in New York Independent System Operator (NYISO) Energy Markets. (Market Participants include all entities that produce, transmit, sell, and/or purchase for resale, capacity, energy, and ancillary services, in the NYS wholesale market. Table1.1-1 in the Guide identifies the categories of Market Participants.

NYISO Ancillary Services Manual
http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf

This manual describes the six NYISO Ancillary Services: (1) Scheduling, System Control, and Dispatch; (2) Voltage Support; (3) Regulation and Frequency Response; (4) Energy Imbalance; (5) Operating Reserves; and (6) Black Start Capability. It includes an explanation of the services, sources and recipients of the services, payments required, performance criteria and penalties, and other associated procedures.

NYISO Transmission Congestion Contracts
http://www.nyiso.com/public/webdocs/documents/manuals/operations/tcc_mnl.pdf

This document contains the rules, procedures, and guidelines regarding the TCC Auctions administered by the NYISO as described in the NYISO Services Tariff. The purpose for this Manual is to identify and explain rules, procedures, and guidelines regarding TCC Auctions.

NYISO Installed Capacity Manual
http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_manual.pdf

This Installed Capacity Manual describes the capacity planning process; computation of Transmission District (TD) and Load Serving Entity (LSE) installed capacity requirements; determination of deficiencies and penalties; and installed capacity resource qualifications.

NYISO Transmission Services Manual
http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf

The Transmission Services Manual defines a) LBMP Load Zones and Transmission Service Sub-Zones; b) Market Participant eligibility and communication requirements; c) Transmission Usage Charge (TUC); d) Transmission Service Charge (TSC); e) NYPA Transmission Adjustment Charge (NTAC); f) Stranded Investment Recovery Charge (SIRC); and g) Ancillary Services Charges.

The document includes an overview of a) Transmission Congestion Contracts (TCCs); b) sale of TCCs; c) congestion payments; d) allocations of sales revenues; and e) treatment of congestion rent excesses and shortfalls.

It includes coverage of a) existing agreements including Transmission Wheeling Agreements (TWA); b) grandfathered rights; c) bilateral transaction scheduling; d) firm and non-firm transmission service; e) NERC transaction tagging; and f) NERC Total Transfer Capability (TTC) and Available Transfer Capability (ATC) criteria.

NYISO Open Access Tariff
http://www.nyiso.com/public/documents/tariffs/oatt.jsp

NYISO Day-Ahead Demand Response Manual
http://www.nyiso.com/public/webdocs/documents/manuals/planning/dadrp_mnl.pdf

This manual describes the Day Ahead Demand Response Program (DADRP). It provides an overview as well as detailed information on eligibility, registration procedures, bidding instructions and examples.

NYISO Emergency Demand Response Manual
http://www.nyiso.com/public/webdocs/documents/manuals/planning/edrp_mnl.pdf

The Emergency Demand Response Program (EDRP) provides a mechanism for load reduction during emergency conditions, more specifically defined in this document.

Appendix B. The New York Independent System Operator

NYISO Background

The New York Independent System Operator (NYISO) is perhaps the single most important institution in the New York electricity marketplace. This appendix provides an overview of the NYISO scope and perspective on which elements of the energy storage value proposition it oversees.

Formation

In 1998 and 1999, the Federal Regulatory Commission (FERC) authorized owners of transmission facilities in New York State to replace the Power Pool with the New York Independent System Operator (NYISO) and related governing organizations, including the New York State Reliability Council (NYSRC).

At that time:

- Key agreements were established regarding new governing organizations; notable agreements include: 1) the New York ISO Agreement (NYISO Agreement), 2) the New York State Reliability Council Agreement (NYSRC Agreement), and 3) the Agreement Between the New York Independent System Operator and the New York State Reliability Council (NYISO-NYSRC Agreement).
- NYISO assumed primary responsibility for operation of the New York State Bulk Power System (NY Bulk Power System) [1] and administration of the newly established competitive electricity market.
- The NYSRC assumed responsibility for overseeing the Reliability Rules previously developed by the Power Pool and the New York State Public Service Commission (PSC) to ensure reliability of the New York State Power System. The NYISO Services Tariff required NYISO and market participants (the parties who participate in NYISO's markets) to comply with the NYSRC's Reliability Rules, and makes NYISO responsible for enforcing the rules.

Scope and Mission Overview

The NYISO mission is "to direct the operation of the New York State (NYS) power system…to supply power to loads while maintaining safety and reliability in compliance with the reliability rules established by the New York State Reliability Council (NYSRC)." The NYSRC rules include: 1) operating policies and standards enacted by the North American Electric Reliability Council (NERC) and

[1] The NYS bulk power system is generally considered to be comprised of elements of the New York Power System including generating units whose rating is 300 MW or greater, and transmission facilities whose voltage is 230 kV and above and other generation and transmission resources whose operation may have a significant impact on the grid in other areas.

2) guidelines and procedures enacted by the Northeast Power Coordinating Council (NPCC).

NYISO duties are specified in provisions of: a) the NYISO Agreement, b) the NYISO/Transmission Owner (NYISO/TO) Agreement, c) the NYISO/NYSRC Agreement, and d) NYISO's tariffs, NYISO's reliability rules (rules, standards, procedures, and protocols established by the NYSRC). (Tariffs and reliability rules are approved by the Federal Energy Regulatory Commission (FERC).)

Key NYISO duties include "procure sources of power and certain ancillary services through open markets that it administers," and oversee "open access" to the electric transmission system in New York by providing "non-discriminatory access for market participants" and by allowing for "meaningful involvement" by market participants in the NYISO's operation.

The NYISO emphasizes its focus on impartial implementation of those responsibilities under non-discriminatory terms for all market participants.

NYISO Responsibilities

The NYISO facilitates the overall electricity marketplace by coordinating several crucial facets of that marketplace. They are: 1) energy sales and purchases, 2) ancillary services, 3) access to/use of transmission capacity, and 4) generation *capacity*. In addition the NYISO manages key elements of grid operation such as controlling important generation and transmission resources and scheduling resource maintenance.

Generation Capacity

The NYISO is responsible for ensuring that there is enough "electric supply" (primarily generation) capacity to satisfy demand for power, especially peak demand. They do that, in part, by administering the "installed capacity" (ICAP) marketplace, primarily by facilitating auctions for ICAP and by managing related transactions.

Wholesale Electric Energy Marketplace

The NYISO facilitates 1) a *day-ahead* marketplace (DAM) and 2) a *real-time* (T) marketplace for electric energy. They do it in large part by using bid data from market participants to set prices.

Prices in both markets reflect "locational based marginal pricing" (LBMP). LBMP includes the costs for 1) electric energy, 2) transmission congestion, and 3) transmission-related energy losses.

See Appendix D for details about LBMP.

Transmission Access and Congestion Management

The NYISO coordinates transmission access and services for the power system, manages congestion on the transmission system, administers related tariffs and charges, and facilitates use of “transmission congestion contracts” (TCCs).

The NYISO administers scheduling of firm and non-firm point-to-point transmission service for the (LBMP) energy market and for bilateral energy and power transactions. The NYISO also provides what is called the Network Integration Transmission Service used by utilities to optimize use of their own generation resources, “import” of electricity from outside of the state, and “wheel-through” service used to transfer electricity through the state’s system.

See Appendix G for more details.

Transmission congestion occurs when transmission lines are overloaded. NYISO responds to congestion to minimize its effects by providing price signals via a congestion component of LBMPs. Some market participants may avoid congestion charges by purchasing TCCs, primarily from entities that owned transmission before the NYISO was formed.

See Appendix F for more details.

Ancillary Services

The NYISO coordinates ancillary services needed to keep the power system operational, reliable, and secure. The five ancillary services include 1) system scheduling control and dispatch, 2) voltage support, 3) regulation and frequency response, 4) operating reserve, and 5) black start. Please see Section A.3.3. for more details and Appendix E for descriptions of ancillary services.

Grid Operations

NYISO authority includes that to control generators, transmission, and other resources which support or use the NYS power system, so those resources are operated in a reliable manner. Market participants with a service agreement with the NYISO must a) comply with the reliability rules, b) follow NYISO procedures and c) furnish required data to the NYISO.

Maintenance Scheduling

The NYISO coordinates a) planned outages for generation resources that are under contract to provide capacity, and b) scheduled transmission down-time. Terms are defined in Appendix A-1 of the NYISO Transmission Owners (TO) Agreement.
http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/nyiso_agreement/nyiso_to_agreement.pdf

Electric Supply Capacity Planning

The NYISO's scope includes establishing location-specific installed capacity (ICAP) requirements as needed to maintain (power) system reliability. Among other criteria used to establish capacity requirements are: status, availability, reliability, and location of existing capacity and the rate and location of demand growth. The NYISO is also responsible for ensuring that Load Serving Entities (LSEs) with which it has service agreements maintain appropriate levels of capacity.

Similarly, the NYISO assesses the reliability of and need for expansion of the NYS Transmission System, commensurate with reliability-related rules. The assessment process is documented in an annual NYS transmission plan.

NYISO Electricity Market

As shown in figure A.2., the NYISO facilitates and administers four elements of the electricity marketplace: 1) installed capacity (ICAP), 2) electric energy; 3) ancillary services; and 4) transmission congestion contracts – TCCs.

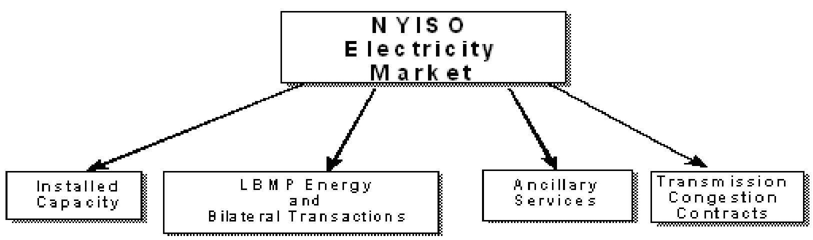

Figure B.1. NYISO Electricity Market

Installed Capacity

The Installed Capacity (ICAP) Market is established to ensure that there is sufficient electric supply capacity (primarily generation) to serve demand, as determined by the NYISO. ICAP related costs reflect the fixed costs for owning the generation, primarily financing and including taxes and insurance.

In broad terms ICAP resources a) provide electric supply capacity with required reliability in the NYCA, b) are "accessible to the NYS transmission system," c) comply with NYISO generation-reliability-related rules. Demand response – dynamically controlled *load reduction* – is one emerging alternative to peaking *generation* capacity.

ICAP *providers* own or aggregate ICAP resources. Installed Capacity *users* are LSEs in the NYCA market. LSEs may satisfy ICAP requirements using bilateral transactions or via the NYISO-facilitated ICAP auction.

The ICAP marketplace and NYISO's roles are described in the NYISO Installed Capacity Manual which is available online at: http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_manual.pdf

LBMP Wholesale Energy and Bilateral Energy Transfers

The NYISO facilitates an electric energy market used by NYS electricity market participants to buy and sell electric energy.

Energy providers sell energy into the New York electricity marketplace or via bilateral contracts. The electricity marketplace is open to all market participants whereas bilateral contracts involve agreements between specific buyers and sellers regarding price, "location" and other related terms.

Conversely, LSEs and other energy purchasers buy energy from the New York electricity marketplace or purchase energy under terms of a bilateral contract with a specific supplier.

Energy prices reflect either a) locational-based marginal price (LBMP) or b) terms of bilateral transactions. LBMP includes components for a) the energy, b) transmission congestion, and c) transmission energy losses.

See Appendix D for details about LBMP.

Energy providers submit offers for energy and for bilateral transactions into the 1) real-time market or 2) day-ahead market (DAM). Load (for demand management) submits bids only into the DAM.

Parties using a bilateral contract may a) bid a transaction as a firm point-to-point transaction – including possible congestion charges paid to ensure energy delivery or b) enter a non-firm point-to-point transaction involving delivery only if congestion charges will *not* be incurred.

At the close of each market, the NYISO initiates a bid evaluation process. The process involves retrieving bids from NYISO's electronic bid system, analyzing the bids with regard to specified criteria, making adjustments to ensure reliability, and posting of results to NYISO's electronic bid system.

Ancillary Services

One of the NYISO's main responsibilities is to facilitate the ancillary services market. Ancillary services: a) support the transmission of energy and reactive power from supply resources to loads, and b) are used to maintain the stability and reliability of the NYS power system.

NYISO coordinates and if necessary controls generation (and other) resources that provide ancillary services and the NYISO is responsible for administration of related tariffs.

Market participants may "self-supply" two types of ancillary services: 1) regulation and frequency response and 2) operating reserve services. If so, the following must occur:

- Entities that self-supply bid the resource (required to provide the respective ancillary service) into the ancillary services market.
- The NYISO selects the successful bidders to provide each ancillary service. The revenue serves as an offset against charges for the service.
- Facilities used to self-supply ancillary service are placed under the operational control of the NYISO.

The other three ancillary services are provided by the NYISO: 1) system scheduling control and dispatch, 2) voltage support, and 3) black start.

See Appendix E for details about the nature of ancillary services.

Transmission Congestion Contracts

One of the NYISO's responsibilities is to manage "congestion" on the NYS transmission system. One way it does so is by administering the transmission congestion component of the LBMP. Another market mechanism that is used to manage transmission congestion is Transmission Congestion Contracts (TCCs).

See Appendix F for details about transmission congestion contracts.

Transmission Access and Charges

Though not one of the four elements of the NYISO Market, as depicted in Figure A.1., the NYISO administers access to the transmission system and the related tariff and charges.

See Appendix F for details about transmission services and charges.

NYISO Market Mechanics

The NYISO market is comprised of a number of inter-related processes designed to ensure efficient and reliable operation of the NYS power system. Four key elements of the NYISO's power market administration include:

- Market Assessment – seasonal to real-time
- Transactions – from bid to bill
- Locational Based Marginal Price – includes components for energy, losses, and congestion, both day-ahead and real-time.

- Risk and reliability Management – for load serving entities and generators

NYISO's market processes, illustrated in figure A.1, include seasonal ICAP requirement/market assessments, week-ahead reliability reviews, Day-Ahead Market (DAM), Real time Commitment (RTC), and Real time Dispatch (RTD).

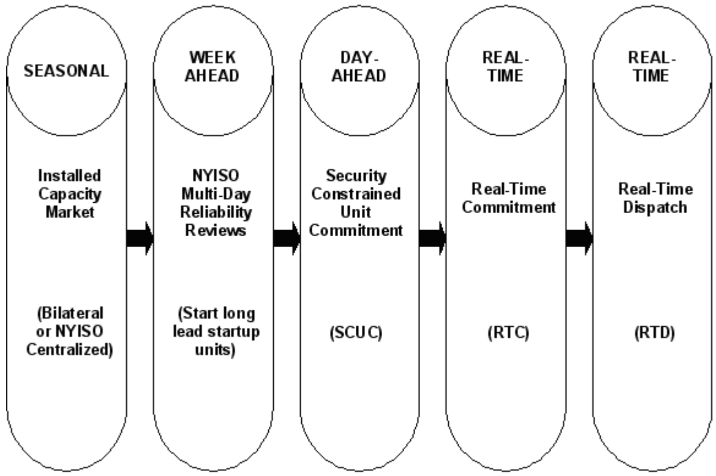

Figure B.2. NYISO Market Processes

Seasonal Planning Process

The seasonal planning process begins with an aggregation of peak load forecasts by LSEs within the NYCA, to estimate the ICAP requirement for each LSE. If an LSE will not have enough ICAP, then it may buy more capacity, buy bilateral contracts or participate in the annual NYISO facilitated auction. Generation capacity providers sell *energy* by 1) establishing bilateral contracts transactions or 2) submitting bids via the DAM.

Week-Ahead Planning

As an important way to predict possible capacity shortfalls, the NYISO requests that ICAP providers submit non-binding bid forecasts for "the week ahead." If an ICAP deficit is possible, then the NYISO may do one or more of the following, to make up for the shortfall: 1) notify market participants about possible curtailments, 2) purchase reserves, or 3) commit resources with long start up times.

Among other benefits, the week-ahead evaluation provides the NYISO with lead-time needed to identify and procure the most effective resources needed to meet possible ICAP shortages.

Day-Ahead Operation

NYISO uses the Security Constrained Unit Commitment (SCUC) software to balance 1) economic/financial considerations with 2) grid stability and security.

SCUC identifies the best blend of supply sources given available resources and bids and when accounting for transmission constraints.

According to the NYISO, the "24-hour commitment optimization strikes a balance between the minimum period in order to ensure reliable operation and allowing the market to have the maximum flexibility for all participants. A 24-hour commitment objective provides the needed balance while not over-extending the NYISO's role of facilitating the market."

Real-Time Scheduling

Real Time Scheduling (RTS) includes the following functional programs:

1) Real Time Commitment (RTC)
2) Real-Time Automated Mitigation Process (RT-AMP)
3) Real Time Dispatch (RTD)
4) Real-Time Dispatching–Corrective Action Mode (RTD-CAM)

RTS supports several important features of the electricity marketplace in New York:

- frequent commitment of resources
- forward-looking dispatch optimization
- second settlement for operating reserves and regulation

RTS reduces the elapsed times from RTC to RTD and provides greater convergence between scheduling decisions and real-time clearing prices. According to NYISO, price convergence occurs due to:

- consistent modeling of reserve requirements in the commitment and dispatch processes
- reduced time between RTC and RTD
- evaluation of the load profile during a given hour

Real-Time Commitment

Real time commitment addresses adjustments needed – to the day-ahead schedule – to reconcile real-time capacity (supply) with demand, as needed.

Bids for capacity used for that reconciliation should be submitted 75 minutes before each hour for full consideration though real-time bids (into the RTC program) may be considered.

According to the NYISO, the RTC does the following:

- Make binding unit commitment and de-commitment decisions for the periods beginning 15 minutes (in the case of resources that can respond in ten minutes) and 30 minutes (in the case of resources that can respond in thirty minutes) after the scheduled posting time of each RTC run

- Provide advisory commitment information for the remainder of the two and a half hour optimization period; and
- Produce binding schedules for external transactions to begin at the start of each hour

RTC also “co-optimizes” a) among all load, operating reserves and regulation service requirements, and b) to minimize the total as-bid production costs over its optimization timeframe. To do so, the RTC accounts for:

- SCUC’s resource commitment for the day
- Load and (energy) loss forecasts – made by the RTC itself each quarter hour
- Binding transmission constraints
- All real-time bids and bid parameters

Real-Time Automated Mitigation Process

NYISO’s Market Monitoring and Performance staff is responsible for timely and accurate detection and mitigation of what NYISO refers to as “the exercise of market power;” presumably including what could be referred to as gaming the system.

NYISO’s Real-Time Automated Mitigation Process (RT-AMP) includes automated “conduct” and “impact” tests and other screens (summarized below), executed in conjunction with the RTC (process) every 15 minutes.

Conduct Test

The conduct test compares the price of energy offers to benchmarks. If offer price exceeds reference price by a specified amount then the conduct test is “tripped.”

Impact Test

The impact test addresses change in price “that would prevail if offer prices were mitigated.” If mitigation of offers would significantly change the prevailing price then this test is “tripped.”

The impact test includes a full resource recommitment and dispatch.

An area-specific variation of the impact test is used to evaluate areas with capacity constraints and/or localized transmission congestion. It trips if local congestion changes significantly.

Considerations

Many rules, parameters, limits, and thresholds are defined to support the mitigation process. Considerations include:

- Determination of super-zones in the NYCA and load pockets in constrained areas;
- Determination of threshold values for each load pocket of a constrained area;
- Determination of the nesting pattern of load pockets;
- Arming of the automated process; and
- Portfolio exclusion that may be applied to super-zones and load pockets.

Mitigation Duration
Mitigation is applied for an entire hour, or for the remainder of the current hour if mitigation begins within the hour.

Real-Time Dispatch

The Real-Time Dispatch (RTD) program

- makes dispatching decisions;
- sends base point signals to internal generators (and, to the extent that the NYISO's software can support their participation, demand side resources);
- calculates real-time market clearing prices for
    - energy,
    - operating reserves,
    - regulation service.
- establishes real-time schedules for those products on a five-minute basis.

RTD evaluations optimize system resources given present circumstances (demand, operating reserves, and regulation service resources and needs) and to "minimize the total cost of production over its nominal optimization horizon of one hour."

The RTD evaluation yields a) a binding schedule for the next five minutes, and b) advisory schedules for the remaining four 15-minute periods of its bid-optimization horizon.

Key RTD includes current information about a) the status of the system, and b) the same bids and constraints addressed by RTC evaluations.

Note that RTD does not address resource *commitments* or related costs when making *dispatching* or pricing decisions.

For the future, NYISO is investigating ways to provide means to respond to "excessive and persistent price differentials between the markets at times when sufficient capacity remains available on the transmission interface to provide substantive reduction in the differential." The cited reason for that situation is that "due to market rules associated with transaction scheduling that require over one hour of advance notice to schedule a transaction and the associated risks to market participants, price differences are not well arbitraged in real-time by market participants."

Real-Time Dispatch – Corrective Action Mode

The Real-Time – Corrective Action Mode (RTD-CAM) is a specialized version of RTD that activates during extraordinary circumstances and at the request of the NYISO.

RTD-CAM operates with different constraints and produces results more quickly than RTD. RTD-CAM activates on demand rather than the periodic activation of the regular RTD. Though normal RTD does not commit additional resources, RTD-CAM may commit fast-start resources to meet energy and reserve requirements. However, RTD-CAM does not "decommit" rapid-start resources once they are dispatched; although it does provide messages to operators when a resource is not operating economically.

Primary Reference

NYISO Market Participants Users' Guide, Customer Technical Services. Version 5.0, 11/9/2005

Appendix C. Installed Capacity (ICAP) Market

The content in this appendix is based heavily on the NYISO Installed Capacity Manual available at the NYISO website: http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_manual.pdf

ICAP Introduction

An Installed Capacity (ICAP) resource is one that a) supplies and/or reduces demand capacity in the NYCA, b) is "accessible to the NYS transmission system," and c) complies with the requirements of applicable reliability rules.

The ICAP Market exists to ensure that there is sufficient electric supply (primarily generation) capacity to serve demand.

- Installed capacity providers own or aggregate ICAP resources. The amount of capacity that each supplying resource is qualified to provide to the New York Control Area is determined by an Unforced Capacity (UCAP) methodology.
- Installed capacity *users* are load serving entities (LSEs) in the NYCA market. LSEs may satisfy ICAP requirements using bilateral transactions or via NYISO-facilitated ICAP auctions (described below). LSE's requirements are based on "forecasted contribution to its transmission district peak load, plus an additional amount to cover an Installed Reserve Margin."

The ICAP Market is competitive by design. And, according to the NYISO: "The ICAP market provides an important link to the…day-ahead market program because it "is designed to insure that there are sufficient resources…to meet the NYISO's day-ahead forecast load and capacity requirements."

Note that ultimately it is "Unforced Capacity" (UCAP) that is purchased. According to NYISO, UCAP represents the "net anticipated useable capacity when outages and other generator operating characteristics are considered."

The NYISO has six ICAP resource categories:

1. Generators and system resources (SRs)
2. Energy-limited resources such as hydroelectric facilities late in the Summer or Autumn
3. Interruptible load resources
4. Municipally owned generation
5. Special case resources (SCRs) including smaller and some demand response resources (other than interruptible loads)
6. Intermittent power resources such as wind and solar power systems.

ICAP Certification and Reporting

Most reporting and settlement activities are for the NYISO. Two reports are required for the NYISO: test results and monthly ICAP certifications, described below.

Test Results – The NYISO may call for a test of registered ICAP resources classified as "special case" resources (SCR). The test resembles a curtailment with a two hour notification period. Tests last for one hour. SCRs must demonstrate its capacity each capability period, either using a curtailment or the test.

Certification (by NYISO) is required for all ICAP resources, including that sold through the NYISO and that which is sold bilaterally. ICAP suppliers submit certification information by the 20th day of each month. As part of the monthly certification, ICAP suppliers must show that they made arrangements to accommodate any derating of their ICAP.

ICAP Market Mechanisms

<u>ICAP Auctions</u>

The NYISO facilitates the ICAP market using periodic auctions that allow capacity providers to offer capacity for purchase and LSEs to bid for the capacity (UCAP). In New York about 45% of the capacity needed is procured at these auctions. Transactions are worth over $850 million (in 2005).

There are three types of auctions: 1) Capability Period "Strip Auction," 2) Monthly Auction, and 3) monthly Spot Market Auction. ICAP-related purchase and sales transactions are handled by an automated system.

The first type – the strip auction – enables ICAP providers and users to enter into a six month contract (corresponding to the NYISO "capability period"). One strip auction is held prior to each capability period. The second type of auction is the monthly auction that is typically held around the 12th day of each month. And there is the spot (or deficiency) auction, which is held so LSEs and other users with a capacity deficit may buy additional capacity.

<u>UCAP Demand Curves</u>

As depicted in figure C.1, the UCAP price is for the (expected) amount of UCAP needed. NYISO uses a "demand curve" to price UCAP if there is too little or too much UCAP.

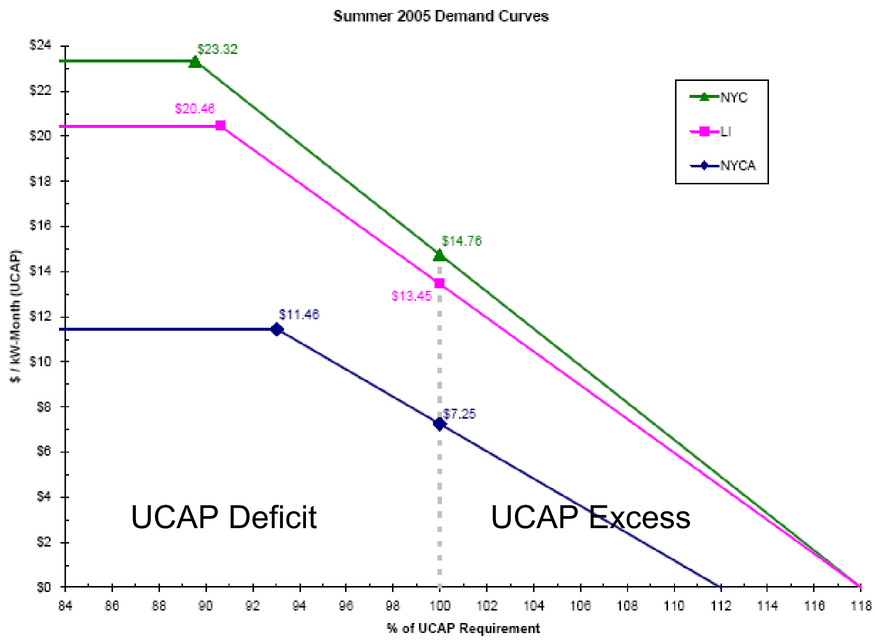

Figure C.1. UCAP Demand Curves, Summer 2005.

If there is just enough UCAP – represented by the point on the demand curve's X axis labeled 100% – the price is set at the price established during the strip auction. If there is a UCAP deficit the price is higher, up to a maximum price. If there is an excess of UCAP the price drops as a function of the amount of excess.

Table C.1. UCAP Demand Curve Information for Summer 2005.

ICAP/UCAP Translation of Demand Curve
~ Summer 2005 Capability Period ~

	ICAP Based Reference Points Monthly ($/kW-Month)	Summer 2005 ICAP/UCAP Translation Factor	**UCAP Based Reference Points** Monthly ($/kW-Month)
	Col. A	Col. B	Col. C = Col. A / (1-Col. B/100)
NYCA	$6.88	5.08%	**$7.25**
NYC	$13.92	5.66%	**$14.76**
LI	$12.74	5.28%	**$13.45**

	ICAP Based Maximum Clearing Price Annual ($/kW-Year)	Monthly ($/kW-Month)	Summer 2005 ICAP/UCAP Translation Factor	**UCAP Based Maximum Clearing Price** Monthly ($/kW-Month)
	Col. A	Col. B	Col. C	Col. D = Col. A/12 / (1-Col. C/100)
NYCA	$130.50	$10.88	5.08%	**$11.46**
NYC	$264.00	$22.00	5.66%	**$23.32**
LI	$232.50	$19.38	5.28%	**$20.46**

	UCAP Requirement (MW @ 100% Req.)	Demand Curve Zero Crossing %	UCAP at $0 (MW @ Col. B %)	Demand Curve Slope (in UCAP) ($/kW-Month) per **100 MW**
	Col. A	Col. B	Col. C = (Col. A) x (Col. B)	Col. D = $\frac{-100 * \text{Ref. Point}}{\text{Col. C - Col. A}}$
NYCA	35,799.2	112%	40,095.1	**-$0.1688**
NYC	8,526.8	118%	10,061.6	**-$0.9617**
LI	4,904.9	118%	5,787.8	**-$1.5234**

Supporting Activities

Auctions are, perhaps, the most important ICAP market activity; however, there are other important activities that support the orderly functioning of the ICAP market. Other notable activities are summarized as follows:

- Transmission Owners (TOs) develop load forecasts that are used to establish UCAP requirements for LSEs.
- Market participants (i.e., suppliers, aggregators, LSEs) that trade UCAP are required to report UCAP purchases and sales including information about who bought and who sold the UCAP. This “certification” is a mechanism used by the NYISO to ensure that LSEs have sufficient UCAP.
- Special Case Resources (SCRs) – a likely categorization for distributed/modular storage – must be registered with the NYISO prior to participation in the ICAP market providing specific information related to their ability to curtail load or generate when called upon. SCRs are small resources, which are not controlled or monitored directly by the NYISO, playing an increasing role in the electricity marketplace.

- Each month, electricity suppliers provide generation facilities' availability data to the NYISO. That data is used to determine generators' UCAP.
- Market participants may track their financial position over time. using detailed billing summaries that include auction activities, financial true-up information and rebates are provided.

UCAP Capacity Prices for 2005 and 2006

The following are strip auction results for Winter 2005-2006 Capability Period and for Summer 2005 and 2006 Capability Periods.

Based on those values UCAP capacity in NYC was worth about $14.70/kW month throughout the year, or about $175/kW-year. For capacity before "derating," the price is just under $13.9/kW-month throughout the year, or about $167/kW-year.

Strip Auction Results 2005 to 2006

The following are strip auction results for the Summer 2006 Capability Period and the Winter 2005-2006 Capability Period.

Table C.2. UCAP and ICAP Prices for Summer 2006.

	UCAP		Derating Factor (% EFOR)	ICAP	
	Awarded (MW)	Price ($/kW-month*)		Required (MW)	Price ($/kW-month)
NYC	2,187	12.35	5.4%	2,306	11.68
Long Island	4	6.50	3.5%	4	6.27
Rest-of-State	3,015	1.44	5.4%	3,179	1.36
Total	5,206	6.03**	5.4%	5,489	6.01*

*$ Bid value/price for six month period ÷ 6.

**Weighted Average

Table C.3. UCAP and ICAP Prices for Winter 2005-2006

	UCAP		Derating Factor (% EFOR)	ICAP	
	Awarded (MW)	Price ($/kW-month*)		Required (MW)	Price ($/kW-month)
NYC	1,846	5.11	5.2%	1,942	4.85
Long Island	15	0.68	5.2%	16	0.64
Rest-of-State	2,987	0.62	4.2%	3,112	0.59
Total	4,849	2.33**	4.6%	5,069	2.32*

*$ Bid value/price for six month period ÷ 6.

**Weighted Average

Primary Reference

Installed Capacity Manual. February 2006. Available on the NYISO website at: http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_manual.pdf

Appendix D. Location Based Marginal Pricing

Location Based Marginal Price (LBMP) is a key element of the NYISO Market Operation. LBMPs reflect the time and location specific price for serving load on the margin. The price reflects bids submitted by participating sources. Units are $/MW for one hour ($/MWh).

Electric Power and Energy

The rationale for use of LBMP begins with the principle of efficient economic operation (of a given resource fleet) as it relates to generation of electric energy. Based on that principle; "the least costly way of producing electric energy is achieved when all generators supply energy at a rate (MW level) such that the price of one more MW of capacity is the same for all unconstrained units." The price of providing that additional increment of power – the marginal price – will be the same for all generators and loads. This ideal operating condition is known as "equal lambda" dispatch.

In reality – given losses and capacity constraints in power systems – equal lambda dispatch based entirely on generators' marginal cost (or bid) may not be the most efficient and/or reliable way to serve load. Two primary reasons for that are: 1) energy is lost as it moves within the transmission system and 2) electric supply resources may have to be operated in a way that addresses overloaded or congested transmission capacity rather than operating to minimize cost of production.

Transmission Energy Losses

During electricity transmission some energy is lost. NYISO scheduling accounts for the losses when power needs are assessed. In New York the LBMP includes a component for the losses (called the marginal losses component).

According to NYISO positive and negative marginal losses component of the LBMP is driven by the following factors:

- The marginal losses component of the LBMP at a bus is positive when a small increase in generation at the bus causes an overall decrease in transmission losses.
- Conversely, the marginal losses component of the LBMP at a bus is negative when a small increase in generation at the bus causes an overall increase in transmission losses. The effect of generation on losses is measured in terms of delivery factors with respect to the reference bus.

Transmission Congestion

Increasingly there are circumstances when specific nodes and corridors within the transmission system are heavily loaded such that it cannot transfer needed power (also called being congested). In some of those circumstances economically efficient operation of *generation* conflicts with effective operation of the *transmission* system. When that happens electricity must be supplied by resources whose cost is relatively high, such as generation that does not use the congested transmission circuit(s). Congestion related costs are added to the LBMP in the form of a congestion cost component.

Based on NYISO documentation; the cost of congestion (component of the LBMP) is influenced mostly by the following:

- The marginal congestion component of the LBMP represents the combined effect of all the flow constraints in the NYCA. Congestion exists when either a flow is violating load carrying capacity limits or when current flow through transmission is held constant at the limit.
- To relieve an overload or to maintain current flow at the limit, the two leading options are to:
    - Increase generation on the receiving side of the flow
    - Decrease generation on the sending side of the flow

The NYISO manages only generation output, not load; so the LBPM marginal congestion component depends on the degree to which a generator affects congestion. This effect – known as the generation shift factor (GF) – is applied to changes in area loads, external interchange schedules, and generation schedules to project pre-contingency line flows which indicate potential system security problems.

See Appendix F for details.

Reference Bus LBMP

LBMPs are defined with respect to a NYISO-selected reference bus. The LBMP for the reference bus is the least cost to serve a load while accommodating transmission constraints. The LBMP "establishes the marginal price for energy, which is the basic component of the LBMP at all the other buses in the system."

Each reference bus LBMP* has the following components:

- Marginal price for energy (usually positive);
- Marginal price for losses (positive or negative);
- Marginal price for congestion (positive or negative);

*One LBMP is used for an entire zone (including all subzones).

So, in practice LBMP reflects the location-specific price that participants in the electricity marketplace:

- Will pay a generator to inject power at that location, or
- Will charge a load for the power withdrawn from a subzone.

Risk Management

NY electricity marketplace participants can manage exposure to the volatility of the LBMP market using several approaches.

Load Serving Entity

Load serving entities (LSEs) can address price volatility risk as follows:

- Enter into a firm or a non-firm "bilateral" contract.
    - non-firm contract terms – use the power only if congestion charges will not be incurred.
- Lock in price for some or all energy needed in the DAM, which is less volatile.
- Bid into the DAM using a price cap (the maximum price that will be paid).
- Buy TCCs to manage the cost of congestion.
- Use energy storage to store less expensive off-peak energy, with little or no congestion impacts and reduced T&D losses (relative to importing energy on-peak.

Electricity Provider (primarily generation)

- Provide ICAP
- Supply energy, reserve or regulation, or any mix of these (within the limits of actual plant capability).
- Bid power into the DAM, the real-time market, the supplemental market, or you can provide power through a firm or a non-firm bilateral contract (subject to a conclusion of a private contract for the bilateral transaction).
- Satisfy bilateral contract obligations entirely from generation owned by specifying appropriate price bid. Or, supply part of the obligation using energy purchased from the market and supply the balance from generation owned, with the portions being determined automatically by the NYISO based on bids.

Primary Reference

Source: NYISO Market Participants Users' Guide, Customer Technical Services. Version 5.0, 11/9/2005

LBMPs 2003 – 2005 Average

		Energy Prices Constant 2005$ -- January 2003 through September 2005						
			$/MWh					Zonal
Zone	Year	Summer	Summer	Summer	Summer	Winter	Winter	Average
		Peak	Super Peak	Off-Peak	Shoulder	Peak	OP/Shoulder	(All Hours)
Zone A	**2005**	59.61	81.40	46.84	52.00	60.43	49.36	50.11
Zone B	**2005**	61.35	83.21	49.62	54.07	64.65	53.05	53.29
Zone C	**2005**	63.17	84.05	50.33	55.33	65.23	53.10	53.78
Zone D	**2005**	61.09	80.63	49.46	54.36	67.08	53.19	53.33
Zone E	**2005**	65.78	86.11	52.68	57.86	68.48	55.72	56.47
Zone F	**2005**	69.76	92.33	55.32	61.31	71.82	58.95	59.52
Zone G	**2005**	75.33	109.14	56.39	63.45	71.13	58.34	60.23
Zone H	**2005**	79.91	115.23	58.24	66.08	71.97	59.46	62.20
Zone I	**2005**	78.98	117.61	57.71	65.83	70.86	59.23	61.71
Zone J	**2005**	**94.76**	**136.54**	**67.94**	**80.80**	**96.12**	**69.27**	**73.64**
Zone K	**2005**	104.10	146.94	72.65	85.97	89.54	69.48	76.31
Statewide Average	**2005**	**(All Hours)**		***64.31***				
Statewide Avg. ("K" not included)	**2005**	**(All Hours)**		***62.37***				

Energy Price Assumptions and Notes:

(1) Energy prices reflect a load-weighted average hourly day-ahead NYISO wholesale electric price from January 1, 2003 through September 30, 2005 (in constant 2005$$)

(2) For months in 2005 in which load data was not available from the NYISO, the first corresponding week in the same month in 2004 was used for weighting purposes.

(3) Ancillary service costs are NOT included

(4) "Statewide" energy price is a zonally-weighted average of zones "A" through "K"

(5) Statewide average minus Long Island removes zone "K" from the average

(6) Summer peak is June through August weekdays from noon through 6:00 p.m., exclusive of summer super peak hours

(7) Summer super peak is a load-weighted average of the 5 highest annual peaking load days for each year from June through August weekdays from noon through 6:00 p.m.,

(8) Summer off-peak is June through August from midnight through 8:00 a.m. on weekdays; all weekend hours June through August; and all May, September and October hour

(9) Summer shoulder is weekdays June through August from 8:00 a.m. through noon and 6:00 p.m. through midnight

(10) Winter peak is December through February weekdays from noon through 8:00 p.m.

(11) Winter off-peak & shoulder is all hours from November through April not included in winter peak

(12) New Year's Day, July 4th, and Christmas are assumed all Off-Peak hours

(13) 2005 MAPS Base Case statewide real growth rate (without Long Island) of 1.06% will applied to actual LBMPs through 2007 (RMs drop below 18% in 2008 due to a lack of addition assumptions) (assumption under review as of 9/05.)

Appendix E. Ancillary Services in New York

The Five types of ancillary services listed below are summarized in the following subsections:

1. Scheduling, System Control & Dispatch
2. Voltage Support
3. Regulation and Frequency Response
4. Operating Reserve Service
5. Black Start Service

Ancillary Service 1. Scheduling, System Control & Dispatch Service

The System Scheduling, Control & Dispatch (SSC&D) service involves management of key facets of the power system.

- tie-line regulation
- time error
- system restoration
- operating reserve
- generator outage scheduling

Price for this service includes all related NYISO's costs including its cost for scheduling, system control, and dispatch. The service is funded via charges – per Rate Schedule 1 – to direct customers and suppliers. Transmission users purchase this service from the NYISO.

Ancillary Service 2. Voltage Support Service

For the Voltage Support service the NYISO provides reactive power to maintain transmission system voltages. The NYISO coordinates with transmission owners (TOs) regarding operation of reactive power supply and voltage control facilities.

Payments made for entities that provide this service are made using revenues collected from users of the service under terms of NYISO's Rate Schedule 2.

Ancillary Service 3. Regulation and Frequency Response Service

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

Regulation transactions occur in what NYISO calls a “full two-settlement market” characterized by the following:

- The NYISO selects regulation service in the Day-ahead Market (DAM) from qualified generating resources that bid to provide regulation service
- In RTD, regulation providers are selected because of a second co-optimization of energy, reserves, and regulation based on real-time need and supply.
- Suppliers buy out of day-ahead schedules based on actual schedules and operations in real-time.

Ancillary Service 4. Operating Reserve Service

This service is, in essence, backup generation for the grid. It is needed after a major area- or region-wide power system disruption, especially loss of a major power plant or transmission corridor. Power from operating reserve resources must be available to the NYISO within 30 minutes, maximum. Two-thirds of that capacity must be available within 10 minutes.

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

Note that providers of reserve capacity submit bids that include an energy price *and* a price for the capacity. The NYISO uses those bids to identify the combination of energy and reserve capacity resources with the lowest total cost (co-optimized resources). So storage capacity that is bid into the reserves market must be charged and ready to provide energy at any time when it is providing reserve capacity. Said another way; under current market rules--reflecting an electric supply system dominated by large generation resources--some benefits from storage used for reserve capacity cannot be internalized.

For example, demand related to charging of storage could be curtailed very quickly to reduce load almost instantaneously, when reserve capacity is needed (similar to aggregated demand response programs). And, storage that is fully charged--probably for purposes other than to provide reserve capacity--could provide very rapid-response reserve capacity, without being operated at all. By contrast; most generation-based reserve capacity is provided by operating generation facilities at part load; the unused capacity “picks-up” additional load when reserves are needed. Operating combustion-based power plants at part load usually increases fuel use, emissions, and maintenance cost.

The operating reserve service is provided through a “full two-settlement market” characterized by the following: The NYISO procures operating reserve capacity from available, dispatchable generation using the day-ahead market.

- In RTD, reserve providers are selected because of a second co-optimization of energy, reserves, and regulation. Suppliers buy out of day-ahead schedules based on actual schedules and operations in real-time.

The NYISO offers this service to transmission customers. Transmission customers may purchase this service from the NYISO or may self-supply the service.

- NYISO selects operating reserve service from available, dispatchable generation in the DAM
- In RTD, reserve providers are selected because of a second co-optimization of energy, reserves, and regulation. Suppliers buy out of day-ahead schedules based on actual schedules and operations in real-time.

Ancillary Service 5. Black Start

The black start service is needed after an area- or region-wide power system disruption. It is provided by generators that can start and operate without an external source of electricity; to provide power for system restoration controlled by the NYISO.

Payments made to black start service providers are based on “approved embedded costs” associated with activities related to providing the service, including incremental operations and maintenance and training costs “which allow the generator to self-start in the absence of network-supplied synchronous power.”

Transmission owners/operators purchase this service from the NYISO though the NYISO also facilitates localized black start service transactions.

Energy Imbalance Service

While often thought of as an ancillary service, the NYISO, does not offer an energy imbalance service separately. Instead; the two-settlement energy market serves as a proxy for the service via individual transactions.

Ancillary Services Primary Reference

NYISO Market Participants Users’ Guide, Customer Technical Services. Version 5.0, 11/9/2005

Storage for Two Ancillary Services, Introduction

Generally regulation and reserves services are provided by generators that are on-line and operating a) at or above minimum output rating, and b) below maximum rating. Generation owners forgo energy sales so they may, instead, sell ancillary services. The price for ancillary services is mostly a function of the opportunity cost – revenues and profits that would accrue if the generation provided energy rather than ancillary services – rather than being driven by generation cost. One result is that prices for ancillary services tend to be more volatile than energy prices [1] And, notably, ancillary services requiring a more rapid response have higher prices.

Ancillary services are mostly capacity-related rather than being energy-related. For example, generators providing regulation requires variation of plant output to be above and below a base operating point; energy supplied at the generator's base operating point is not part of the regulation provided. In fact, the energy output associated with regulation nets out to zero over a timescales of several hours as the generator output varies, between being above and being below its base operating point.

One advantage of storage for regulation is that it can be dedicated to supplying regulation without the need to also supply energy, like generation does. That because storage can "absorb" energy (charging) and "inject" energy (discharging). The effect is that storage can act as a load sometimes and like generation at other times. Energy lost during the charge/discharge cycle is purchased at the prevailing market rate.

Similarly operating reserve is also a capacity service. Reserves are always available (a characteristic of capacity resources) though it is actually used infrequently (limited amounts of energy are used). Any incidental injection of energy into the grid – that occurs when reserves are used – is sold at the prevailing price for energy.

The price for reserves is denominated in units of power ($/MW). The price applies to capacity that is *available* as a reserve resource during a specified a period of time (e.g. a specific hour of the year). Payment is made whether or not an available resource is actually used.

Reference

[1] Hirst, Eric and Kirby, Brendan. Creating Competitive Markets for Ancillary Services, ORNL/CON-448, Oak Ridge National Laboratory, Oak Ridge TN, October 1997.

Appendix F. Transmission Congestion Payments and Transmission Congestion Contracts, Introduction

Transmission Congestion, Introduction

Transmission congestion occurs when transmission lines become heavily loaded due to too much demand relative to available capacity. Among other effects: a) some scheduled energy transfers may have to be cancelled, b) energy prices may rise in affected areas, and c) the power system may become somewhat or even very unstable.

The NYISO is responsible for managing transmission congestion in the NYS power system. In the day ahead market (DAM) energy bids are evaluated and a (generation) commitment schedule is developed which accounts for expected and possible transmission system line and interface constraints/congestion.

To avoid overloading specific transmission circuits, the NYISO may respond by using electric supply resources in ways that reduce/avoid congestion, which often leads to a deviation from what would otherwise be the least-expensive (bid-price) generating resource mix. If so, the cost (and thus price) of energy will be higher in areas affected by constraints.

See Appendix G for details about transmission *service* charges.

Transmission Congestion Cost Component (of LBMP)

To account for the price difference described above, the NYISO includes a congestion component in the price paid for a) LBMP electricity purchased from the central power marketplace, or b) point-to-point transmission service provided to participants in bilateral contracts.

Firm transmission service is for market participants that agree to pay the congestion charges and non-firm transmission service is for market participants that do not want to pay for congestion. In some cases, users of non-firm transmission service can buy into the firm capacity market, to the extent that that market is under subscribed (i.e., there is still unused capacity).

Users of firm transmission service may satisfy the congestion component of LBMP by purchasing transmission congestion contracts (TCCs) from entities that own or have rights to transmission capacity that is not available via the LBMP marketplace.

Appendix G provides more details about transmission charges.

Transmission Congestion Contracts (TCCs)

Introduction

This section is derived from a paper entitled Markets for Financial Transmission Rights. The paper's scope is a survey of "markets for financial transmission rights (FTRs) around the world." In New York FTRs take the form of transmission congestion contracts (TCCs). [1]

Background

Because electricity flows according to Kirchoff's laws and is difficult to trace, it is difficult to quantify and manage actual energy flows through the transmission system. Historically, transmission capacity has been defined – for the purposes of market-based pricing – with respect to simplistic, pre-defined "paths." An evolutionary version of that concept was use of "flow-based" paths; an attempt to address actual electrical performance of the transmission system. The preferred approach is use of pricing for "point-to-point service" with implicit flows based on energy injection and extraction.

Introduction to Financial Transmission Rights

Transmission plays an increasingly important role in the competitive electricity marketplace, as does the basic principle of open access and non-discrimination. An open access (transmission) system allows electricity buyers and sellers to move electricity purchased in an increasingly competitive electricity marketplace.

As transmission systems become heavily loaded, electricity transfer congestion increases. Various ways to address congestion have emerged. A leading approach involves adding the marginal cost incurred to overcome congestion (between two points) to the location-specific marginal price of energy. Typically this so-called congestion component of total energy price is collected by the independent system operator (ISO) and distributed to recipients.

Financial Transmission Rights Properties

Financial transmission rights (FTR) comprise one important element of a competitive electricity marketplace with open access and with congestion and congestion-related charges for electricity. FTR "holders" are entitled to receive the value of congestion-related payments for the quantity of TCCs held, as established by the locational price difference. Those payments – generically called congestion rents – are administered by the ISO.

The mathematical formulation for FTR value (congestion rent) is:

$$FTR = Q_{iw}(P_w - P_i)$$

P_w is the energy price at the point of withdrawal w. P_i is the energy price at location i. Q_{iw} is the quantity to be transmitted across the path from point i to point w.

Market participants holding appropriate FTRs (for energy transfers made) will, in effect, be reimbursed for the amount paid for congestion charges. So a holder of an FTR for transmission between a generator located at point A and serving its load at point B is indifferent to any congestion-related difference in the locational prices between the generator and its load. Said another way, "If the contractual volume matches the actual traded volume between two locations, an FTR is a perfect hedge against volatile locational prices."

ISOs determine the total FTR capacity needed based on predicted results or a forecast, and allocate FTRs to holders based on established criteria and on estimates of future transmission capacity.

The difference between the congestion rent and payments to FTR holders may be positive, resulting in a surplus to the ISO. The surplus is redistributed to FTR holders and transmission service customers. However, payments to FTR holders in excess of congestion rent reduce payments proportionally to FTR holders, or transmission owners make up the difference.

Most often, FTRs are allocated through an auction, though FTRs may be allocated to transmission service customers that pay transmission system related embedded costs. Typically, the auctions are designed by ISOs to reflect the respective market's characteristics.

Financial Transmission Rights – Market Implications

The property rights defined by FTRs: a) allow market participants to reap financial benefits associated with transmission capacity, and b) facilitate efficient use of scarce resources.

FTRs provide an important step down the path toward transmission open access; a critical element of a competitive electricity marketplace.

FTRs provide means to convert historical entitlements to "firm" transmission capacity into tradable contracts while transmission owners (TOs) are indifferent and can actually "cash out" when other entities can make more economically efficient use of the transmission capacity.

The property rights associated with FTRs reward investments in new transmission capacity by allowing the investor to offer tradable contracts. And, efficient pricing of FTRs provides important price signals regarding the location of investment needs for generation and transmission capacity.

FTRs provide a way for risk-averse market participants to hedge against uncertainty regarding congestion charges. The option to hedge transmission price is an important way to facilitate an efficient electricity market.

TCCs in New York

As one element of a congestion management framework, New York established financial instruments called transmission congestion contracts (TCCs). As described above and as emphasized by the NYISO, a TCC is a *financial obligation* to compensate the holder for congestion-related costs. A TCC is not a *physical right* to move electricity.

A TCC – which is specified between two locations and is uni-directional – pays the holder congestion rents based on the actual transmission congestion (and cost) experienced between those locations in the DAM.

Purchasing TCCs provides a virtual equivalent of firm transmission service (described in Appendix G) for bilateral energy contracts.

As a point of reference, ConEd expects to receive approximately $60 million of revenue from TCCs annually. [2]

TCC-based firm transmission service facilitates economic dispatch and trading because the owner of a TCC receives the value of its rights independently of physical operation.

TCCs for Hedging Congestion Costs

TCCs provide a way for Market Participants to pay a fixed charge for transmission service ahead of time, thereby hedging their exposure to transmission congestion.

All grandfathered rights and TCCs held by an investor-owned utility are considered held for the benefit of their transmission customers.

Buying and Selling TCCs

TCCs may be bought or sold through direct sales or at auction. Before auctions TOs may sell grandfathered TCCs (defined below) and residual TCCs (defined below) that were allocated before the NYISO's formation. Those TCCs are sold directly via the TO's Open Access Same-time Information System (OASIS).

Residual TCCs allocated prior to the NYISO's existence that are not sold directly are included in the TCC auction. Grandfathered TCCs may be sold directly, at auction, or TOs may retain them.

TCCs for time durations ranging from six months to five years may be sold at auction. The relevant NYISO tariff provides for an auction process that facilitates sale of TCCs.

A TCC auction is held by the NYISO in advance of each planning period – TCCs sold are for transmission capacity that has become available due to expiration of: 1) TCCs sold in previous auctions, 2) grandfathered transmission contracts, and 3) TCCs released for sale by the owner ("primary holder").

TCC auction participants need not be DAM participants.

Transmission Congestion: Key Definitions and Concepts

Congestion Charges – Participants in the LBMP market pay congestion charges for transmission service when congestion exists unless they have necessary TCCs. If a market participant buys LBMP energy, the congestion charge is embedded in the LBMP. If the participant has scheduled bilateral transaction(s) then the congestion charge is part of the TUC. If available, TCCs (with the necessary POW and POI) may be purchased in lieu of paying congestion charges.

Congestion Rent – The holder of a TCC collects (and in some cases pays) congestion rent as payment for the TCC. Congestion rent is applied to each MW served, for the DAM, for transmission service between a) the POI for the respective TCC, and b) the POW.

Grandfathered Rights – Parties to existing agreements that do not convert to TCCs will hold *Grandfathered Rights.*

Grandfathered TCCs – Parties that convert *Grandfathered Rights* to TCCs will hold *Grandfathered TCCs.*

Residual Transmission Capacity – *Residual Transmission Capacity* is the transmission capacity remaining after all grandfathered TCCs and grandfathered rights have been accounted for.

Residual TCCs – A portion of *Residual Transmission Capacity* was allocated to the TOs as residual TCCs prior to the formation of the NYISO.

TCCs – TCCs are financial obligations. A TCC, which is specified between two locations and is uni-directional, pays the holder the congestion rent based on the actual transmission congestion experienced between those locations in the DAM. TCCs can provide the financial equivalent of firm transmission service to support bilateral contracts and are cleared in the DAM. Ownership of a TCC is not a physical right to move power. TCC-based firm transmission service facilitates economic dispatch and trading because the owner of a TCC receives the value of its rights independently of physical operation.

TCC Holders – When the NYISO was formed, the TOs were still bound through pre-existing agreements to serve certain wholesale loads and to honor contracts with other TOs and third parties. The NYISO Tariff provides incentives for parties of these agreements to move toward the new market structure by providing the opportunity for transmission customers to convert their rights under existing agreements to TCCs.

Primary Reference

NYISO Market Participants Users' Guide, Customer Technical Services. Version 5.0, 11/9/2005

Secondary References

[1] Kristiansen, Tarjei. Markets for Financial Transmission Rights. Norwegian University of Science and Technology, Department of Electrical Power Engineering. May 2004.

[2] State of New York Public Service Commission. Case No. 04-E-0572. Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. For Electric Service. Statement of Support of Joint Proposal. December 15, 2004

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Joskow, P. and J. Tirole. Transmission Rights and Market Power on Electric Power Networks, RAND Journal of Economics, 31: 450-487. 2000.

Appendix G. New York Transmission System, Services and Charges

Transmission Zones and Subzones

The NYS transmission system is segregated into 11 “internal” zones and four zones external to the NYCA. These zones are those for which LBMPs are established. NITS also has designated 23 transmission service areas (sub-zones; each zone has one or more sub-zones).

Zones reflect location relative to key transmission system interfaces. Sub-zone boundaries indicate borders between areas served by different transmission owners within a zone. An entire sub-zone is contained within one zone.

The zones are shown graphically in the diagram in Figure G.1. Solid bold lines indicate connections between zones and may include multiple transmission facilities. Zones A through K are the zones within New York and the four external zones are M through P. Also shown are sub zone elements within zones.

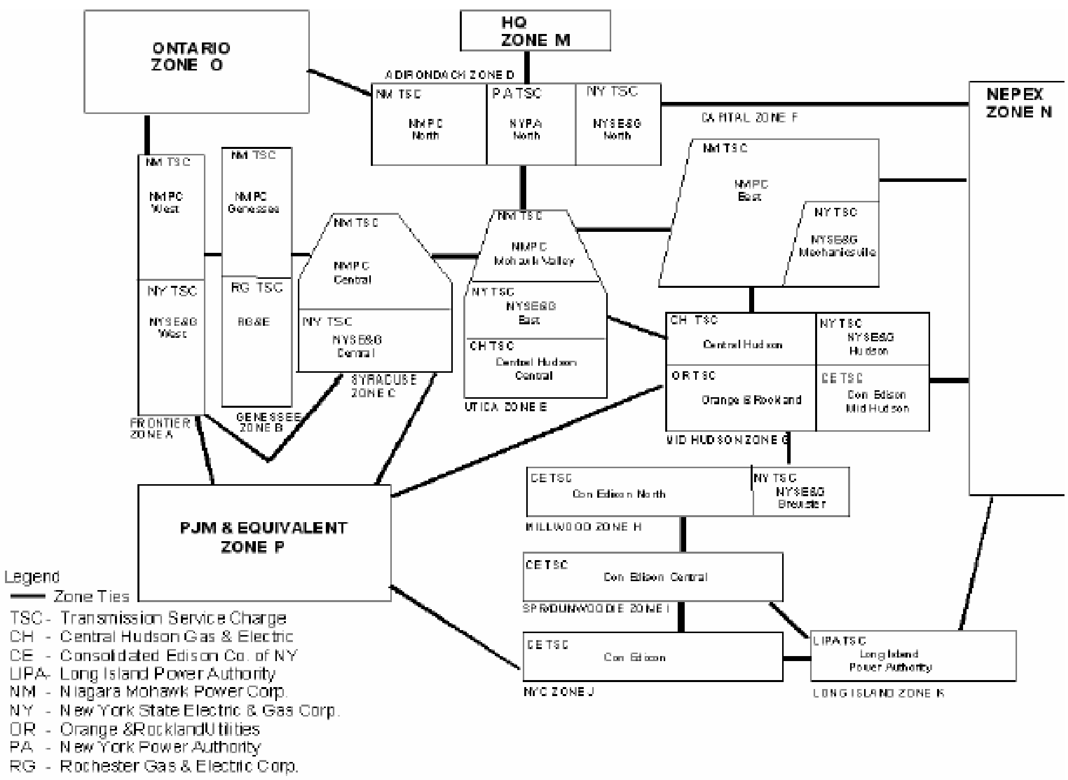


Figure G.1. Schematic Representation of the NYS Power System Zones and Subzones

NYISO Operation, Control and Notification

The NYISO directs operation of transmission facilities that are under "operational control" in accordance with the Reliability Rules. Transmission over which NYISO has operational control has been designated as "Transmission Facilities under NYISO Operational Control."

Operational Control includes: a) security-monitoring, b) adjustment of generation and transmission resources, c) coordination and approval of changes in transmission status for maintenance, d) determination of changes in transmission status for reliability, e) coordination with other control areas, f) voltage reductions, and g) load shedding.

Transmission Owners (TOs) must notify the NYISO regarding changes to the status of transmission facilities designated as "Transmission Facilities Requiring NYISO Notification." Furthermore, the NYISO must approve operational decisions affecting those transmission facilities.

Per NYISO procedures, the NYISO directs TOs' actions, when needed, to maintain or restore system stability.

Transmission Services

Point-to-Point Transmission Service

The NYISO provides Firm and Non-Firm Point-To-Point Transmission Service under terms of the OATT using transmission facilities covered by the NYISO/Transmission Owner (TO) Agreement. Point-To-Point Transmission Service (P-to-P service) provides for delivery of capacity and energy to designated point(s) via the transmission system.

Firm P-to-P service is for users that agree to pay applicable congestion charges (congestion rent), if any. Users may fix the price of congestion rent for firm P-to-P service by purchasing contracts for the necessary amount of capacity, called Transmission Congestion Contracts (TCCs).

Non-Firm P-to-P service is for users that do not want to pay congestion rent; thus if congestion charges apply when service is scheduled then the service is not provided.

Firm Point-to-Point Transmission Service

All requests for firm P-to-P service (and for Network Integration Transmission Service) are given the same priority. Participants in bilateral transactions using firm P-to-P service make a commitment to pay relevant congestion charges. Firm service will not be curtailed unless the NYISO must do so for system reliability.

Schedules for the Transmission Customer's Firm Point-to-Point Transmission Service in Real-Time, must be submitted to the NYISO no later than seventy-five

(75) minutes prior to the dispatch hour. Schedules submitted later than seventy-five (75) minutes prior to a dispatch hour are not accepted into the Real-Time schedule for that hour.

The service is purchased in 1,000 kWh blocks – the amount of energy to be transmitted – within a specific hour.

Transmission customers may change receipt and delivery points to obtain service on a non-firm basis.

Transmission customers taking firm P-to-P service are charged for costs related to re-dispatch of supply resources (e.g. for system security and stability or to relieve congestion), in accordance with Attachment J of the NYISO OATT and Attachment B of the NYISO Services Tariff.

In the event that a curtailment is required to maintain reliable operation of the NYS power system, or a portion thereof, those curtailments will be made on a non-discriminatory basis. If multiple transactions are cancelled due to curtailment, to the extent a) practical,
and b) consistent with utility accepted practice, the NYISO will allocate the curtailment proportionately among customers using the network transmission service and those using the firm P-to-P transmission service.

Non-Firm Point-to-Point Transmission Service

Non-Firm Point-to-Point Transmission Service (non-firm P-to-P service) for transmission of Energy and Capacity is available under terms of Schedule 8 of the NYISO OATT.

Non-firm P-to-P service is available only when there is no congestion between the point(s) where power/energy is injected and the point(s) of delivery. As such, it is given a lower priority than *firm* P-to-P service and network transmission service. (Non-firm P-to-P service and network transmission service from secondary resources are given equal priority.)

If a non-firm transaction is scheduled and congestion occurs later, the transmission service will be curtailed (reduced or interrupted entirely). If so, the generator's “decremental bid” is automatically considered as a bid in the real-time market, unless the generator indicates otherwise.

Load that will not be served if service is interrupted and that is in-state will either a) be served using energy from the LBMP market, or b) be curtailed if price exceeds a “price-sensitive load bid.”

Users of non-firm P-to-P service that are subject to transmission service curtailment for out-of-state loads, (i.e., for wheel-through or for export transactions) must make arrangements for alternate energy supply sources.

Users of non-firm Transmission Service whose needs cannot be served in the DAM due to congestion may upgrade to firm P-to-P service as late as seventy-five minutes before the respective hour.

The NYISO reserves the right to curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service:

a) for reliability reasons when, an Emergency or other unforeseen condition threatens to impair or degrade the reliability of the NYS Transmission System;
b) for economic reasons if the NYS Transmission System experiences Congestion.

Curtailments are made on nondiscriminatory bases. The NYISO provides advance notice of curtailment and interruption to the extent that doing so is consistent with good utility practices.

According to the NYISO "The process of Curtailment of Non-Firm Point-To- Point Transmission Service for Imports, Exports, and Wheel-Throughs may cause these non-firm transactions to incur incidental Congestion charges due to inter-Control Area Curtailment procedures."

Network Integration Transmission Service

The NYISO provides firm transmission service over the NYS transmission system to "network customers" for delivery of energy from those customers' designated network resources, to serve its native load.

This service, called Network Integration Transmission Service (NITS) allows network customers to efficiently and economically utilize their network resources as well as other generation that is not designated as network resources, to serve load.

NITS users must obtain or provide necessary ancillary services. NITS users agree to pay the congestion rent associated with the service, if any, or NITS users may fix possible congestion charges by purchasing appropriate TCCs (i.e., must purchase the necessary quantity – MWs – for the appropriate transmission path(s).

Among other uses, NITS allows network customers a) to optimize integration and dispatch of their own network resources, and b) when there is no congestion; to purchase and deliver low priced energy from non-network resources without additional charge.

Transmission Charges

When transmitting energy through the electric transmission system the primary charges paid by users – generically called a Transmission Service Charge, or TSC – cover the embedded cost for the in-state transmission system. (Some exceptions involve entities operating under terms of pre-existing wholesale transmission agreements that have been “grandfathered”).

Depending on location, season, and time-of-day, transmission users (users) may also have to cover costs associated with:

a) marginal energy losses (transmission energy losses that occur when transmission systems become heavily loaded and over-loaded);
b) congestion charges which reflect the incremental cost incurred due to congestion, for the respective transaction.

Users that schedule bilateral transactions pay congestion-related and energy-loss-related costs via a Transmission Usage Charge (TUC) whereas users that buy energy in the energy marketplace pay loss and congestion related charges, if any, as embedded elements of the applicable LBMP price.

Transmission Service Charge (TSC)

Transmission Service charges are used to determine the cost of providing transmission service for wheel throughs, for export transactions, and for serving load within the NYCA.

The Transmission Service Charge (TSC) represents a key component of the recovery of the total transmission revenue requirements for respective Transmission Owners’ (TO) transmission facilities. Each TO calculates its revenue requirement (for transmission assets it owns) monthly, using a methodology specified by the NYISO.

TSCs are levied by each TO whose system is used to transmit a given portion of energy. That is, for example, if energy passes through three TOs’ systems then each levies its own TSC.

TSCs are denominated in units of $/MWh transmitted.

Retail TSC

Retail electricity customers that use “unbundled” transmission service (e.g., to move electricity among dispersed facilities or from an independent power producer to a load) pay a retail TSC (RTSC). It may be based on FERC approved Revenue Requirements (RR) and Scheduling, System Control and Dispatch Costs and/or a NYS PSC approved rate design for retail transmission service.

Wholesale TSC

Wholesale transmission users (primarily LSEs) pay a wholesale transmission service charge (wholesale TSC, or TSC) whose value is calculated in accordance with Attachment H of the NYISO OATT. It is paid to the respective TO(s). Attachment H of the NYISO OATT describes the wholesale calculation process in detail.

The wholesale TSC applies to the following transmission service

c) from one or more Interconnection Points between the NYCA and another Control Area to one or more Interconnection Points between the NYCA and another Control Area (Wheel-Throughs);
d) from the NYCA to one or more Interconnection Points between the NYCA and another Control Area, including transmission to deliver Energy purchased from the LBMP Market and delivered to such a Control Area Interconnection Point (Exports);
e) to serve Load within the NYCA.

The Wholesale TSC does not apply to:

a) retail transmission service under terms of the relevant TO's tariff or rate schedule that explicitly provides for other transmission charges in lieu of the wholesale TSC, subject to any applicable provisions of the Federal Power Act
b) TOs that use their system to provide bundled retail service to loads within its service area, under terms of a retail tariff on file with the New York State (NYS) Public Service Commission (PSC).
c) TOs that file a separate retail TSC – that is in accordance with its retail access program filed with the NYS PSC-- with FERC.
d) wheel-through and export transactions that have been scheduled with the NYISO to destinations within the New England Control Area provided the conditions in Section 7B.1 (iv) of the NYISO OATT are met.
e) transactions that do not occur due to NYISO-initiated curtailments.

Wholesale TSCs are calculated using embedded cost data from respective TOs and using congestion data provided by the NYISO. TSCs are posted on the Open Access Same-Time Information System (OASIS) on monthly basis. Attachment H of the NYISO OATT describes the wholesale calculation process in detail.

The Wholesale TSC calculation is shown below (calculation criteria are described in the Table).

$$\text{Wholesale TSC} = \{(RR \div 12) + (CCC \div 12) - SR - ECR - CRR - WR\}/(BU \div 12)$$

Equation Variable	Variable Name/Description	Data Provided By
RR	Annual Transmission Revenue Requirement ($)	TO
CCC	Annual Scheduling, System Control and Dispatch Costs of the individual Transmission Owner ($)	TO
SR	Sales Revenue from sales of Transmission Congestion Contracts ($)	TO
ECR	Excess Congestion Rents (congestion imbalance) ($)	NYISO
CRR	Transmission Owner's Congestion Payments received from Grandfathered TCCs and Imputed Revenues from Grandfathered Rights from Existing Transmission Agreements ($)	TO
WR	Wheeling Revenue ($)	TO
BU	Transmission Owner's Billing Units (annual MWh) for the Transmission District (MWh)	TO

Transmission Usage Charge (TUC)

The monthly TUC is paid by transmission users participating in bilateral transactions that involve electric supply for load within the New York Control Area (NYCA), "Wheeling" or "Wheel-Through" service, and electricity export (to another state/Canada). (The TUC does not apply to entities using grandfathered rights.)

The TUC includes two components: a) Marginal Losses, and b) Congestion. The TUC is calculated as the product of: a) LBMP price ($/MWh) at the point of withdrawal (POW) minus the LBMP at the Point of Injection (POI), and b) energy (MWh) delivered or scheduled for delivery. Monthly TUCs reflect the amount of energy used (during the respective month) and the applicable LBMPs at the POI and the POW.

There are two types of TUCs – Hourly Day-Ahead and Hourly Real-Time. In a given month the monthly TUC is the sum of the applicable hourly charges.

Day-Ahead TUC

Hourly Day-Ahead TUCs (Day-Ahead TUCs) are calculated for each hour in the Day-Ahead Market (DAM) using Day-Ahead LBMPs for the respective hour, as indicated by the Security Constrained Unit Commitment (SCUC) evaluation.

Day-Ahead TUCs are used to calculate charges for bilateral transactions scheduled in the Day-Ahead Market. The Day-Ahead TUC is calculated based on the scheduled energy transfer and the Day-Ahead LBMP at the POW and at the POI.

Real-Time TUC

The NYISO calculates Hourly Real-Time TUCs (Real-Time TUCs) for each Real-Time Dispatch (RTD) interval (e.g., nominally every 5 minutes) based on Real-Time LBMPs.

Transmission charges for all new transaction requests or requests for modifications to accepted Day-Ahead schedules, which are accepted and scheduled in the Real-Time market, pay TUCs commensurate with Real-Time LBMPs.

If the NYISO curtails a Day-Ahead or a Real-Time transaction then the TUC does not apply.

TUC Treatment of Transmission Marginal Losses

Transmission customers are responsible for cost of marginal energy losses associated with LBMP energy purchases. Payment is made in the form of the marginal loss component of LBMP. (Both day-ahead LBMPs and real time LBMPs include a marginal loss component.)

Marginal losses are calculated as the marginal loss component at the POW minus the marginal loss component at the POI. For exports and wheel-throughs, the marginal loss component is calculated using a flow-distributed ratio at each of the nodes (tie busses) through which the electricity flows.

Accessing Transmission Tariffs

Tariff information is available at the NYISO website in the following documents: NYISO Open Access Transmission Tariff (OATT), Volume 1, Attachments A & B and the NYISO Open Access Transmission Tariff (OATT), Volume 2, Section II and Section III. http://www.nyiso.com/public/documents/tariffs/oatt.jsp.

Primary Reference

NYISO Transmission Services Manual. Version: 2.0 Revision Date: January 20, 2005. Approved: January 19, 2005. Effective Date: February 1, 2005.

Appendix H. Electricity Bill Reduction

Description of Analysis

Storage is charged at night so that energy is discharged during times when peak demand charges apply, during mid-day. The purpose is to reduce the electric service bill, primarily by avoiding demand charges. The current tariffs do not have a time-of-use component.

Results

The customer's utility bill is reduced by $224/kW-yr if storage is used on weekdays, Summer and Winter, to reduce peak demand and on-peak demand and energy use. That is what might be called "operating benefit." It does not include non-energy variable operating costs (primarily for storage loss-of-life per discharge, which applies mostly to batteries.) For any given project it is the *net* benefit that is most important. That value is the operating benefit minus non-energy variable operating cost. That value must exceed the storage system's equipment cost for the project to be viable (unless additional benefits accrue).

Net benefit is shown for various levels of non-energy variable operating cost (VOC). In Table N.1., VOC of zero yields $224/kW-yr whereas VOC is as high as 6¢/kWh leaves about $150/kW-year of net benefit.

Table N.1. Bill Reduction for Various Levels of Storage Non-energy Variable Operating Cost

Storage VOC*		
¢/kWh	$/kW-year	Net Benefit
0.00	0.0	244
0.02	31.2	212.8
0.04	62.4	181.6
0.06	93.6	150.4

*Variable Operating Cost (not including charging energy)

Assumptions

- Energy storage is installed at a Con Ed customer site under tariff PSC 9, Service Class 9, Rate 1.
- During weekdays, the Con Ed customer uses storage to serve a portion of load for 6 on-peak hours.
- Variable operating cost (VOC) includes capital recovery (decrease in asset value) due to degradation of equipment and O&M cost. It does not include charging cost.
- Cases:

Efficiency	70%			80%		
VOC ($/kWh)	0	.03	.06	0	.03	.06

Tariff

SC9 - Rate 1

Consolidated Edison Company
Large General Service (SC No. 9 - Rate I)
Low Tension
New York City

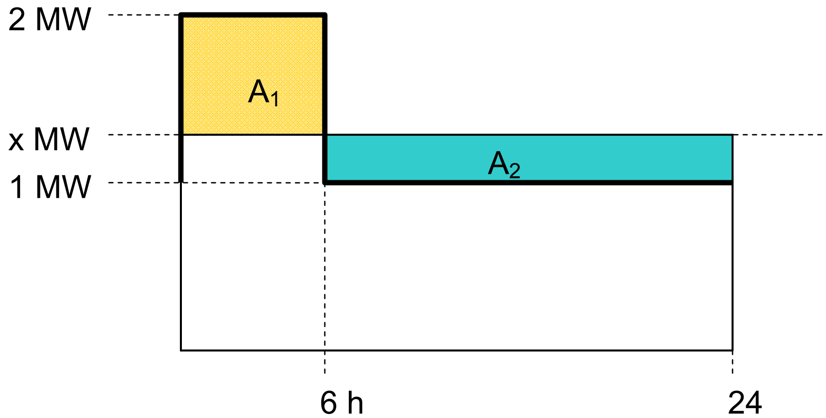
			Summer		Winter	
			Jun - Sep		Oct - May	
Demand Charge ($/kW)	**Reference**		**First 900**	**Over 900**	**First 900**	**Over 900**
Delivery Service	P.S.C. No. 9		13.3400	12.0400	10.66	9.36
Market Supply Charge (MSC)	MSC/MAC - Statement No. 1		7.0600	7.0600	7.0600	7.0600
Monthly Adjustment Clause (MAC)	MSC/MAC - Statement No. 1		0.8200	0.8200	0.8200	0.8200
Subtotal $/kW			21.2200	19.9200	18.5400	17.2400
Increase in Rates & Charges	GRT Statement No. 42	2.8419%	0.6031	0.5661	0.5269	0.4899
Total $/kW			**21.8231**	**20.4861**	**19.0669**	**17.7299**

Energy Charge ($/kWh)	**Reference**		**All**		**All**	
Delivery Service	P.S.C. No. 9		0.0142		0.0142	
Market Supply Charge (MSC)	MSC/MAC - Statement No. 1		0.0815		0.0815	
Monthly Adjustment Clause (MAC)	MSC/MAC - Statement No. 1		0.0055		0.0055	
RPS – Statement No. 1	RPS – Statement No. 1		0.0002		0.0002	
System Benefits Charge (SBC)	SBC – Statement No. 5		0.0016		0.0016	
Subtotal $/kWh			0.1030		0.1030	
Increase in Rates & Charges	GRT Statement No. 42	2.8419%	0.0029		0.0029	
Total $/kWh			**0.1059**		**0.1059**	

Approach

- The only benefit offered by the tariff is savings, with summer demand reduction being worth more than winter demand reduction. (Energy pricing under the tariff is constant for all hours of the year.)
- The decision to operate the BESS is made on a seasonal basis since the demand charge is seasonally adjusted. When demand savings exceed the operating cost (net energy consumption plus VOC), the system would be discharged on all weekdays to maximize benefits.
- During weekends the battery is not operated.
- The weekday load profile is shown in the figure. The BESS is assumed to be sized with adequate power and energy ratings to discharge energy A1. Charging energy A2 includes the effects of turnaround efficiency, or:

$A_2 = A_1 / \eta$	(1)



- The BESS is discharged each day to reduce peak demand to x. A2 is limited in power such that x is not exceeded (which would otherwise introduce unnecessary demand charges). This condition provides for the maximum possible peak reduction. Provided that benefits exceed cost for any power level, the optimal BESS discharge power during the 6-hour window is 2-x. This would limit demand to x during weekdays and 1 MW during weekends. The monthly billing demand would be x.
- From the above geometry and Equation (1), x may be determined as:

$$x = \frac{2\eta + 3}{\eta + 3}$$

- The decision to operate the BESS is made on a seasonal basis (summer and winter). This is determined as follows.

  1. Calculate the demand savings.
  2. Calculate the net energy consumption ($A_2 – A_1$) and the net energy cost.
  3. Calculate the total operating cost (variable cost plus net energy cost).
  4. If the savings – avoided demand and energy charges – exceed total operating costs then operate the BESS.

- Calculate the annual benefits (without costs) by adding the demand savings for each season that the BESS is operated. If the BESS is not operated for a given season, the total seasonal benefit is zero.

Worksheet

ASSUMPTIONS			Notes
Case Parameters			
Efficiency	0.7		
Non-charging variable operating cost ($/kWh)	0.06		
Tariff Data			
Summer Demand Charge ($/kW-mo)	20.4861		Maximum tier
Winter Demand Charge ($/kW-mo)	17.7299		Maximum tier
Energy Charge ($/kWh)	0.1059		All energy, independent of
Operational Data			season and period
Summer operating days	87		5 business days per week
Winter operating days	173		5 business days per week
Demand Impacts	**Summer**	**Winter**	
Demand with Storage	1,189	1,189	
Demand Reduction (kW)	811	811	
Energy Impacts			
Discharge energy (kWh/day)	4,865	4,865	
Discharge energy (kWh/season)	423,243	841,622	
Charge energy (kWh/season)	604,633	1,202,317	
Net energy consumption (kWh/season)	181,390	360,695	
Operating Costs			
Non-charging operating cost ($/season)	25,395	50,497	
Net energy cost ($/season)	19,214	38,207	
Total operating cost ($/season)	44,609	88,705	
Operating Decision			
Demand savings ($/mo)	16,610	14,376	
Demand savings ($/season)	66,441	115,005	
Benefits > Costs	TRUE	TRUE	
Benefits	**Annual**		
Summer benefits ($/year)	66,441		Benefits only. Operating
Winter benefits ($/year)	115,005		cost is not included.
Total benefits ($/year)	181,446		
Total benefits ($/kW-year)	224		
Customer Billing Data - Without Storage			
Days in Billing Cycle	28		
Peak (operating) Days in Billing Cycle	20		
On Peak Consumption (kWh)	240,000		2 MW x 6 hrs x 20 days
Off Peak Consumption (kWh)	552,000		1 MW (18 hrs x 20 days
On-Peak Demand (kW)	2,000		+ 24 hrs x 8 days)
Off-Peak Demand (kW)	1,000		
Reactive Demand (kVar)	0		
Annual Demand (kW)	0		

Appendix I. Electric Supply Reliability in New York, Background

Oversight and Jurisdictions

The following is based on New York Public Service Commission (Commission) proceedings initiated to consider a) adoption of the reliability standards (Reliability Rules) established by the New York State Reliability Council (NYSRC), and b) the criteria for operation and protection of the Northeast bulk power system approved by the Northeast Power Coordinating Council (NPCC). The proceedings address provisions of New York Public Service Law (PSL) §§4(1), 5(2), 65(1), 66(1), and 66(2) and was initiated, in part, in response to enactment of the Federal Energy Policy Act of 2005 (Energy Act) Reliability Rules.[1]

The NYSRC is responsible for establishing and updating standards that "promote and preserve the reliability" of the NYS power grid. Periodically NYSRC amends reliability rules, established in 1999, as needed. All entities engaged in transactions on the New York State power system must comply with the reliability rules. [2]

The NPCC is an international electric regional reliability council that establishes criteria, and coordinates system planning, design, and operations to promote reliable and efficient operation of the interconnected bulk power systems throughout the Northeast and eastern Canada.

The primary scope of the Federal Energy Regulatory Commission (FERC) has been regulation of cost and price affecting wholesale power markets and the interstate transmission grid. Under terms of the Federal Power Act (FPA) §215 titled Electric Reliability, FERC is now authorized to approve mandatory national reliability standards that are developed by an organization that is certified by the FERC. That same section of the FPA allows the state of New York to adopt reliability standards that are more rigorous than the national standards:

> The Energy Act established a new regulatory framework to ensure the reliability of the nation's bulk electric system. FERC assumes jurisdiction in matters regarding reliability over a new entity to be established (the Electric Reliability Organization (ERO)), certain functions of regional reliability entities, and all users, owners, and operators of the nation's bulk power system. Section 215 establishes a process for promulgation of mandatory reliability standards for the nation's bulk power system. The ERO is responsible for developing mandatory national reliability standards, subject to FERC's approval, and authorized to delegate to regional entities the responsibility to propose standards to FERC for its approval and to enforce national reliability standards.
>
> States are not pre-empted from taking action to ensure the safety, adequacy, and reliability of its electric system, as long as such

action is not inconsistent with any mandatory national reliability standard. A significant exception is made for New York State: "[T]he State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the reliability standards" approved by FERC under Section 215.6 [3]

LOLE Reliability Criterion

LOLE is an acronym for loss of load expectation. It is the key reliability metric for a power system. The New York power system “is planned to meet a LOLE that is less than or equal to an involuntary load disconnection that is not more than once in every 10 years or 0.1 days per year. This requirement forms the basis of New York’s installed capacity or resource adequacy requirement.” [2]

References

[1] State of New York Public Service Commission. CASE 05-E-1180 - In the Matter of the Reliability Rules of the New York State Reliability Council and the Criteria of the Northeast Power Coordinating Council. ORDER ADOPTING NEW YORK STATE RELIABILITY RULES. Issued and Effective February 9, 2006

[2] NYISO. Comprehensive Reliability Planning Process Supporting Document and Appendices For The Draft Reliability Needs Assessment Prepared by the NYISO Planning Staff for the Electric System Planning Working Group and the Transmission Planning Advisory Subcommittee. December 21, 2005.

[3] New York State Reliability Council (NYSRC) Reliability Rules For Planning and Operating the New York State Power System Version 15 December 10, 2005 New York State Reliability Council, L.L.C.

Appendix J. Reactive Power Compensation using Distributed Energy Resources

Background

The following is based on research findings produced by Oak Ridge National Laboratory for work whose objective involved an evaluation of the potential of distributed generation (DG) to provide reactive power compensation for voltage control to the grid. Specifically, the work tests the hypothesis that “DG can play a larger and more significant role than at present in relieving voltage stability problems due to both a) suboptimal dispatch of reactive power supplies, and b) reactive power supply shortages.”

Electrical characteristics of power grids and of electric loads lead to undesirable voltage (level) variations due to phenomena called reactance. Reactance occurs because power using, generating, and transmitting equipment often exhibit characteristics like those of inductors and capacitors in an electric circuit. In simple terms, for systems that use alternating current electricity** (like the power grid) inductors cause current to “lead” the voltage and capacitors cause current to “lag” voltage, as shown in the figure below.

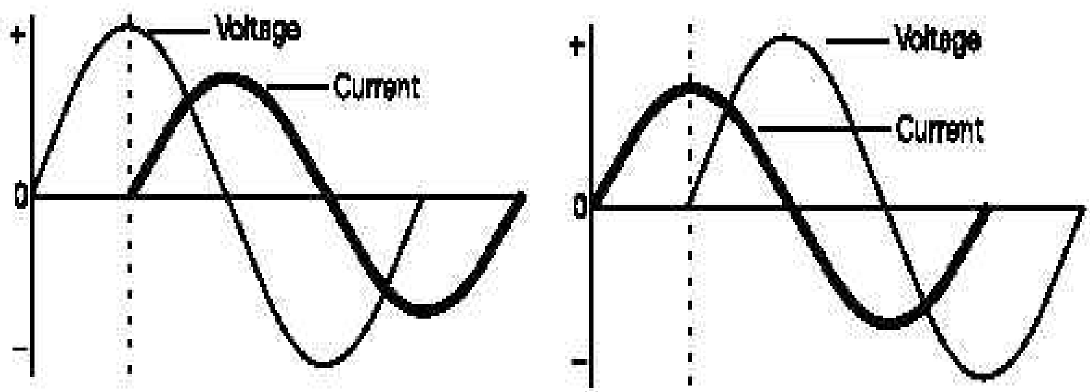


Figure J.1. Leading and Lagging Current due to Inductance
and Capacitance (Reactance) in an Alternating Current Circuit

To the extent that current leads or lags the voltage, the effectiveness of the power system is reduced because reactance reduces the voltage within the T&D system. Said another way: ideally current and voltage are perfectly synchronized. When current and voltage are not synchronized utilities use various means to compensate for the presence of reactance, to restore voltage to the desired level.

**Alternating current (AC) power involves current flow (and voltage) which varies between a positive and a negative level. Electricity power systems use AC power which oscillates between negative and positive values 60 times per seconds – also known as “60 cycle” AC. Among other advantages, AC power enables transmission over longer distances than systems using “direct current” (DC) power; which is power that has a constant current and a constant voltage.

One such technique is to produce “reactive power” – power that has lagging or leading current. The correct amount of reactive power (also called volt-amps reactive or VARs) cancels out effects of reactance in the power system.

(The normal or primary type of power used – power that is not reactive – is called “real power.” In simple terms real power is the type of power that is produced when current and voltage are in synch. Real power is the type of power required for end-use equipment that uses electricity. Real power is often quantified in units of kilowatts or kW.)

Reactive power for voltage compensation is compelling for several reasons. Among other reasons given by the author of the ORNL report is that “past power blackouts have been attributed to problems with reactive power transport to load centers.” In addition, though reactive power for voltage compensation is a relatively small *portion* of total cost to generate and transmit electricity, it does account for billions of dollars in *total* cost. Another reason is that newer central generation technologies are not well suited to use for reactive power generation (they are mostly baseloaded generation designed and optimized for real power generation at a constant output or wind generation whose output is often intermittent). Conversely new technologies – such as modular energy storage, modular generation, power electronics, and communications and control systems – make new alternatives possible.

Voltage Compensation using Reactive Power

The process of managing reactive power in transmission systems is well understood, technically. The three primary objectives of reactive-power management are: 1) maintain adequate voltages throughout the transmission system under normal and contingency conditions, 2) minimize congestion that affects flow of real power, and 3) minimize real-power losses.

FERC separates voltage control into two categories: 1) generation-based, and 2) transmission-based. Generation-based voltage control is an “ancillary service” and transmission-based voltage control is included as an element of transmission service agreements or tariffs.

Generation-based reactive power supply (or voltage support/control) is needed for operation of regional power systems and electricity markets. (Other common ancillary services, include spinning reserve, contingency, emergency, or supplemental reserve, and regulation.) According to authors, “It is variously estimated that providing this bundle of ancillary services costs the equivalent of 10-20% of the delivered cost of electric energy.” [1] [2]

Voltage control is usually centralized because coordinated control is needed among the various entities and equipment on the system, to ensure effective operation of the system (i.e., to keep voltage levels within necessary levels). And, system operators and planners use sophisticated computer models to design and operate the power system reliably and economically; these functions are not readily distributed to individual “sub-regions” or to separate market participants.

In simplest terms voltage control for an alternating-current power system is accomplished primarily by managing reactive power. That is accomplished by injecting reactive power and/or or absorbing reactive power, when needed, as close as possible to the location where reactance is a problem.

The amount of reactive power needed normally varies as a function of the transmission line loading; heavily loaded lines require more reactive power than lightly loaded lines. As reactive power needs in the transmission system vary, the Independent System Operator (ISO) and Regional Transmission Organizations (RTOs) adjust the supply of reactive power.

An important responsibility of power system planners is to address what is generically called “grid security.” It involves planning whose goal is to ensure adequate operation of the power system (generation and transmission) during a range of conditions and contingencies. It involves, in part, modeling of the electric grid system under a broad range of conditions. The purpose is to ensure that the grid has adequate reserves when transmission lines or generators fail, and during peak demand periods. (Normally, power systems maintain enough reserves to serve load should a major generation plant or transmission line fail, commonly called an N-1 (N minus 1) contingency.

Reactive-power resource technologies differ significantly with respect to a) the amount of reactive power that can be produced under given conditions, b) response speed, and c) capital cost. Reactive power sources can be categorized as either static or dynamic.

Common static sources include T&D equipment such as capacitors at substations. Notably, these T&D-based options are considered to be part of the utility’s capital investment portfolio (of infrastructure equipment). The cost (for the equipment) is added to the utility “revenue requirement” – the amount of revenue required, from users, to cover all costs.

Typically dynamic sources include a) generation facilities which are capable of producing both real and reactive power, and b) synchronous condensers, which produce only reactive power. Generation equipment may be owned either by utilities or independent entities. Often reactive power is bought and sold so cost is covered by market-based or market-like prices.

Providing Reactive Power Locally

A key difference between reactive power supply (reactive power) and other ancillary services is that reactive power has to be provided locally because, compared to real power, reactive power cannot be transmitted over long distances. Reactive power needs occur in direct proportion to a) the distribution of load across a system, and b) the proximity between generators and load centers.

Reactive power from DG (and DESs) could provide distributed, dynamic voltage control in response to variations of reactive power needs within distribution systems. (To be a reactive power resource the DG or DES must have the capability to provide and to absorb reactive power. Conversely, DG and DES that does not have the ability to generate or absorb reactive power can *degrade* voltage.)

Notably, many DGs and DES are connected to loads and/or to the grid via equipment that incorporates solid-state power electronics which may be designed to provide reactive-power compensation.

The implications and possibilities for reactive power compensation using DER – in lieu of or in conjunction with large, centrally-dispatched generation – are not well understood. However, reactive power is currently provided, in part, by distributed sources (e.g., static VAR compensators and capacitor banks). So, intuitively, it seems there likely that there are exploitable synergies between the localized need for reactive power (usually near loads) and increasing emphasis on DERs.

References

[1] Li, F. Fran. Kueck, John. Rizy , Tom. King, Tom. Evaluation of Distributed Energy Resources for Reactive Power Supply, First Quarterly Report for Fiscal Year 2006. Prepared for: US Department of Energy, by Oak Ridge National Laboratory and Energetics Incorporated. November 8th, 2005.

[2] Kirby, Brendan. Hirst, Eric. Ancillary Service Details: Voltage Control. Oak Ridge National Laboratory. Energy Division. Sponsored by The National Regulatory Research Institute. Report ORNL/CON-453. December 1997.

Appendix K. Spinning Reserve from Distributed Energy Resources

Responsive load (commonly referred to as demand response or DR) has the potential to provide what is commonly referred to as reserves. Reserves include “fast response” spinning reserve (seconds to hours) and “back-up” or emergency reserve with slower response (minutes to hours). Similarly, modern modular energy storage systems (MESs) that are well-placed could also provide reserves, if enough is aggregated into blocks and if the blocks can be controlled, in concert like larger “central” resources.

Though DR and DES are not used to provide spinning or emergency reserves – for important historical reasons – recent advances in communications and control technologies may enable use of DR and DES as reserve resources.

“North American Electric Reliability Council (NERC), Federal Energy Regulatory Commission (FERC), Northeast Power Coordinating Council (NPCC), New York State Reliability Council (NYSRC), and New York Independent System Operator (NYISO) rules are beginning to recognize these changes and are starting to encourage responsive load provision of reliability services.” [1]

One example of DR that has potential as a reserve resource is the Carrier ComfortChoice responsive thermostat technology. It is designed to reduce summer peak electric demand by controlling residential and small commercial air-conditioning loads. This resource is used to reduce peak demand by several utilities including some in New York, such as Consolidated Edison (ConEd), Long Island Power Authority (LIPA), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

Based on an analysis of results for the summer of 2002 from LIPA scientists at Oak Ridge National Laboratory concluded:

> …the program demonstrates that loads are different from generators and that the conventional wisdom, which advocates for starting with large loads as better ancillary service providers, is flawed. The tempting approach of incrementally adapting ancillary service requirements, which were established when generators were the only available resources, will not work. While it is easier for most generators to provide replacement power and non-spinning reserve (the slower response services) than it is to supply spinning reserve (the fastest service), the opposite is true for many loads. Also, there is more financial reward for supplying spinning reserve than for supplying the other reserve services as a result of the higher spinning reserve prices. [1]

As of 2003 LIPA had an estimated 75 MW of spinning reserve potential from responsive thermostat and about 30 MW for ConEd.

It is important to note that this report is solely an Oak Ridge National Laboratory product and the views expressed are those of the author. While LIPA data were used, LIPA did not agree to participate in testing or verification of the hypothesis.

Reference

[1] Kirby B. J. Spinning Reserve From Responsive Loads. Oak Ridge National Laboratory Report # ORNL/TM-2003/19, under U.S. Department of Energy under contract DE-AC05-00OR22725. March 2003.

Appendix L. Modular Distributed Energy Storage, an Introduction

For a variety of reasons, development of large energy storage projects (e.g., whose power output is many tens of MW to several hundred MW and whose discharge duration is several hours) is usually quite challenging. Just siting such a plant can be a problem unless it is located in an industrial or remote location.

Many otherwise good sites for bulk energy storage development are 1) not close enough to transmission corridors or 2) would have to use congested transmission; so it would be challenging to transfer energy to loads, especially on-peak.

Pumped hydroelectric energy storage projects are likely to face strict oversight with respect to effects on the environment in general and waterways and water quality specifically. Compressed air energy storage (CAES) involves combustion so developers must contend with many of the same environmental and safety challenges as generation plant developers.

An emerging alternative is use of small, modular energy storage (MES) systems located at or near loads. Similarly there is increasing interest in “geographically targeted” load energy efficiency (EE) and demand response (DR) as well as distributed generation (DG).

The opportunity is enabled by state-of-the-art and advanced storage, power electronics, communications, and control technologies along with increasingly sophisticated storage system design and integration techniques and tools. With those advances it is now possible to use distributed MES to serve specific loads and/or as aggregated power “blocks” that can be dispatched in concert, to mimic the effects of dispatching one large central power plant. Blocks totaling tens of MW to hundreds of MW could serve area-specific or regional demand and power system needs.

Importantly, modular resources may be optimized to serve specific needs, when and where needed. And because they may be located *where* needed it is possible for modular resources to provide several “locational” benefits in addition to electric supply related benefits (i.e., reduced need for generation capacity and fuel). Some potentially compelling locational benefits include reduced T&D congestion, reduced T&D energy losses, and distribution upgrade deferrals.

The Official Role for Distributed Resources in NYC, 2006 to 2008.

The following are excerpts from Public Service Commission (PSC) Case document for Consolidated Edison’s Three Year Electric Rate Plan, for 2006 to 2008.

Among other topics the new plan "Endorses cost effective demand management (energy efficiency, distributed generation, and load management) as a means for meeting in whole or in part projected load growth of approximately 535 MW in the three years commencing April 1, 2005." That amount, 535 MW is comprised of "83 MW in Zone I, a 5.5 percent increase over 1,497 MW, and 452 MW in Zone J, a 4 percent increase over 11,308 MW. (Con Edison's electric service territory comprises 100 percent of Zones I and J.)

Though T&D related benefits were not specified, the case does indicate the following regarding the benefit/cost for DG, DM, and EE measures: "To the extent T&D investment might also be avoided, the benefit-to-cost ratio…would even be higher."

Existing systems benefits charges (SBC) programs (referred to as SBC II) are expected to yield 250 MW of DM in the Company's service area.

Incremental programs to provide up to another 300 MW of DM would be developed as a result of this case. Regarding the 300 MW, according to the PSC Case document:

1) Con Edison would have primary responsibility for achieving up to 150 MW of targeted EE and DG to reduce load on constrained delivery networks, with its first Request for Proposals (RFP) or other offering to be issued within nine months of this order.

2) NYSERDA would have primary responsibility for achieving up to 150 MW of EE, load management, and DG throughout the Company's electric service territory.

And, the case document indicates that Con Edison should take general action to enable distributed *generation* as follows:

> Various actions would be taken by Con Edison to facilitate DG development in its service territory. For example, the Company would: (a) extend the existing Standard Interconnection Requirements to DG facilities of up to five megawatts in size (the standard otherwise applies to DG facilities up to two megawatts); (b) provide information about areas without fault current limitations and the schedule for upgrading breakers; (c) post important DG information on its website; and (d) file and serve DG status reports two times per year.

Demand Response: Implications for Storage

As one source of insight about the possibilities for MES authors suggest that readers investigate the growing body of work addressing "responsive loads" or "demand response" (DR). A significant amount of research addresses use of what could be called controllable load reduction that, in aggregate, is used like large "system resources."

Consider that energy storage can provide the same service as demand response; indeed in some cases it may facilitate demand response if the storage carries load when the utility asks users to reduce demand. And, MES can provide other benefits such as reducing customer-side effects from reduced power quality or service interruptions, local reactive power for voltage support and others.

Consider the following from a DOE report to Congress[DOE1] in 2006:

> Sections 1252(e) and (f) of the U.S. Energy Policy Act of 2005 (EPACT) state that it is the policy of the United States to encourage "time-based pricing and other forms of demand response" and encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public. The law also requires the U.S. Department of Energy (DOE) to provide a report to Congress, not later than 180 days after its enactment, which "identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" (EPACT, Sec. 1252(d)).
>
> States should consider aggressive implementation of price-based demand response for retail customers as a high priority, as suggested by EPACT. Flat, average-cost retail rates that do not reflect the actual costs to supply power lead to inefficient capital investment in new generation, transmission and distribution infrastructure and higher electric bills for customers. Price-based demand response cannot be achieved immediately for all customers. Conventional metering and billing systems for most customers are not adequate for charging time-varying rates and most customers are not used to making electricity decisions on a daily or hourly basis. The transformation to time-varying retail rates will not happen quickly. Consequently, fostering demand response through incentive-based programs will help improve efficiency and reliability while price-based demand response grows.
>
> The most important benefit of demand response is improved resource-efficiency of electricity production due to closer alignment between customers' electricity prices and the value they place on electricity. This increased efficiency creates a variety of benefits, which fall into four groups:
>
> - *Participant financial benefits* are the bill savings and incentive payments earned by customers that adjust their electricity

demand in response to time-varying electricity rates or incentive-based programs.

- *Market-wide financial benefits* are the lower wholesale market prices that result because demand response averts the need to use the most costly-to-run power plants during periods of otherwise high demand, driving production costs and prices down for all wholesale electricity purchasers. Over the longer term, sustained demand response lowers aggregate system capacity requirements, allowing load-serving entities (utilities and other retail suppliers) to purchase or build less new capacity. Eventually these savings may be passed onto most retail customers as bill savings.
- *Reliability benefits* are the operational security and adequacy savings that result because demand response lowers the likelihood and consequences of forced outages that impose financial costs and inconvenience on customers.
- Market performance benefits refer to demand response's value in mitigating suppliers' ability to exercise market power by raising power prices significantly above production costs.

<u>Demand Response Primary Reference</u>

[DOE1] U.S. Department of Energy. Benefits of Demand Response in Electricity Markets and Recommendations for Achieving them. A report to the United States Congress. February 2006.

Aggregation

Aggregation involves grouping of distributed resources into what could be called power blocks.

The reference for this subsection of the appendix is a report produced by the National Renewable Energy Laboratory (NREL) to address the topic of aggregation of distributed generation (DG) in New York. Results are, for the most part, applicable to modular energy storage.

The stated objective for that work was to demonstrate aggregation of backup generators by adding controls to make them dispatchable as an aggregated resource. Generators were considered for use as spinning reserve, to pickup interruptible load, and to provide peak power to the utility grid. Results include quantified costs and benefits and characterized technical and institutional challenges associated with services that could be supplied by a DG system aggregator.

An aggregation system performs three functions:

1. Monitor the status of participating backup generators.
2. Dispatch units remotely.

3. Conduct transactions with the NYISO.

To perform those three functions, requires, at least:

1. Control and monitoring equipment installed on DG units.
2. A central dispatch center for the collection of information and dispatch of generators.
3. Communications links for:
    - o Transferring information from field generators to the control center
    - o Remote control of generators from the control center
    - o Communication with the NYISO and other involved parties.

Control and monitoring equipment should provide dispatch and remote monitoring of generators and meet the following requirements:

- Control equipment must ensure that the generators can be dispatched, protected from external faults, and isolated from the utility system if the system fails and ensure that the utility system is protected from a fault in the backup generator
- Backup generators must be operational within a certain time (to be determined by the NYISO) in case of a declared NYISO system emergency without affecting availability for local emergency service.
- Control equipment should provide for remote start/stop of generators if the owner permits operation of its generators in such a manner.

As of September 2004 the DG aggregation system included more than 50 sites with a total capacity of more than 40 MW as part of these six programs in New York:

1. NYISO Installed Capacity (ICAP) Market
2. NYISO Emergency Demand Response Program
3. NYISO Day-Ahead Market
4. Long Island Power Authority (LIPA) Peak Reduction Program
5. New York Power Authority Peak Reduction Program
6. Con Edison Distribution Load Reduction Program

Selected results from the study include the following:

- Cost to aggregate generation, including environmental permitting, was an estimated $55/kW to $60/kW.
- The incremental cost for aggregation (of generation) has a one year payback – based on the assumed number of curtailment calls (approximately 25 hours per month)

Aggregation Primary Reference

Electrotek Concepts Inc. and New York State Energy Research and Development Authority. Aggregated Dispatch of Distributed Generation Units. For National Renewable Energy laboratory (NREL). September 2004. NREL Report# NREL/SR-560-36662.

Appendix M. Market Potential Estimation Details

Statewide Load

Table M.1. Projected Peak Load (MW) for 2006, in New York

Utility/Area	Load (MW) July 26 2005 Hour Ended 5:00 PM, Weather Normalized (Load + Losses)	Regional Load Growth Factor	Forecasted 2006 Load (MW) at Time of NYCA Peak
Central Hudson	1,138.60	1.021	1,162.50
Consolidated Edison	13,299.10	1.0076	13,400.00
Long Island Power Authority	5,184.30	1.0097	5,234.60
Other LSEs	54.20		54.20
Municipals	94.20		95.20
Other adjustments	22.00		22.20
New York Power Authority	581.60	1.005	584.60
New York State Electric & Gas	2,811.00	1.001	2,813.80
Full Requirement Customers	36.70		36.70
Partial Requirement Customers	80.90		81.00
Niagara Mohawk	6,622.90	1	6,622.90
Full Requirement Customers	213.10		213.10
Partial Requirement Customers	126.20		126.20
Jamestown	89.30		89.30
Orange & Rockland Utilities	1,098.00	1.0292	1,130.00
RG&E	1,604.20	1.008	1,617.00
Partial Requirement Customers	11.40		11.50
Total	33,068*		33,295

*NYCA 2005 Weather-normalized peak load, net of station power.

Source: NYISO

Statewide ICAP and UCAP Requirements for 2006

Table M.2. shows the estimated Load, ICAP and UCAP requirements for various utilities in New York, and for New York City, for 2006.

Table M.2. Load, ICAP and UCAP Requirements in New York

2006 ICAP Requirements (May - April)

Transmission District	2006 Forecast Peak Load (MW)	ICAP Requirement (MW)	Effective ICAP %	Summer 2006 UCAP Requirement (MW)	Effective UCAP %
Central Hudson	1,162.5	1,371.7	118.00%	**1,297.3**	111.59%
Con Edison	13,400.0	15,812.0	118.00%	**14,953.4**	111.59%
LIPA	5,406.2	6,379.3	118.00%	**6,032.9**	111.59%
NMPC	7,051.6	8,320.9	118.00%	**7,869.1**	111.59%
NYPA	584.2	689.4	118.00%	**651.9**	111.59%
NYSEG	2,931.5	3,459.2	118.00%	**3,271.3**	111.59%
Orange and Rockland	1,130.0	1,333.4	118.00%	**1,261.0**	111.59%
RGE	1,628.5	1,921.6	118.00%	**1,817.3**	111.59%
Total	33,294.5	39,287.5		37,154.2	

Statewide requirements

NYCA ICAP Requirement set at 118% of 2006 forecast peak				
NYCA ICAP Requirement	=	1.18 x	**33,294.5**	MW
	=	**39,287.5**	MW	
NYCA UCAP Calculation =NYCA ICAP Requirement* (1-NYCA EFOR)				
NYCA EFOR	=	5.43%		
1-NYCA EFOR	=	94.57%		
NYCA UCAP Requirement	=	**111.59%**	**33,294.5**	MW
	=	**37,154.2**	MW	

Locational requirements

NYC ICAP requirement is 80% of peak load	
NYC UCAP requirement is the NYC peak load * (80% * (1- NYC EFOR))	
NYC EFOR =	5.42%
1 - NYC EFOR =	94.58%
NYC Peak Load =	11,627.8
NYC UCAP =	**8,798.1**

LI ICAP requirement is 99% of peak load	
LI UCAP requirement is the LI peak load * (99% * (1- LI EFOR))	
LI EFOR =	3.48%
1 - LI EFOR =	96.52%
LI Peak Load =	5,348.0
LI UCAP =	**5,110.3**

Source: NYISO

In-City Distribution Loads

The data shown in Tables M.3.A. and M.3.B. is based on results form a recent study by ConEd whose purpose is to estimate loads from the various customer classes, as defined by tariffs.

Table M.3.A. Customer Class Loads in NYC (kW)

Class	Season	Non-Coincident Peak Demand	Half Hour Demand at Time of Class Peak, Unadjusted	Adjusted Demand at the Meter	Adjusted Demand at the Generator	System Peak Response	TOD Tariffs
SC No 1	Summer	8,182,421	3,732,162	3,893,889	4,103,150	3,451,391	
	Winter	5,923,228	2,108,378	2,182,869	2,300,179	2,088,700	
SC No 1-WH	Summer	45,580	14,274	15,588	16,425	13,819	
	Winter	44,069	11,295	11,721	12,351	11,492	
SC No 3	Summer	854,376	488,148	499,966	526,836	492,128	
	Winter	736,088	344,224	357,233	376,432	348,902	
SC No 14-I	Summer	163	151	178	188	169	
	Winter	165	114	134	141	129	
SC No 4	Summer	509,367	461,756	473,902	499,233	485,829	
	Winter	357,245	293,760	303,684	319,917	262,265	
SC NoTOD	Summer	1,069,977	1,015,600	1,012,337	1,064,400	1,036,623	1,069,977
	Winter	816,213	753,525	751,999	790,673	670,594	816,213
SC No 5	Summer	1,810	1,449	1,419	1,459	1,397	
	Winter	1,553	1,072	1,056	1,086	1,077	
SC No 5TOD	Summer	20,364	16,301	15,600	16,053	15,233	20,364
	Winter	21,288	14,953	14,337	14,754	14,212	21,288
SC No 6	Summer	2,291	2,291	2,291	2,414	97	
	Winter	2,348	2,348	2,348	2,474	2,192	
SC No 7	Summer	101,230	32,375	34,820	36,691	26,695	
	Winter	144,237	56,500	60,006	63,230	57,898	
SC No 8	Summer	460,532	417,623	436,020	459,453	388,644	
	Winter	271,954	241,699	251,729	265,257	246,511	
SC No 8TOD	Summer	42,595	40,455	39,386	41,503	35,955	42,595
	Winter	24,390	23,557	23,178	24,424	22,928	
SC No 9	Summer	3,891,391	3,121,600	3,179,797	3,350,118	3,242,065	
	Winter	3,004,038	2,227,662	2,305,527	2,429,017	2,131,766	
SC No 9TOD	Summer	757,288	698,255	696,082	730,136	715,680	757,288
	Winter	579,470	498,779	497,825	522,180	482,758	579,470
SC No 12	Summer	27,265	22,601	25,081	26,429	22,279	
	Winter	48,035	38,887	43,129	45,447	41,100	
SC No 12TOD	Summer	38,348	36,123	35,469	37,375	33,521	38,348
	Winter	63,006	59,977	59,036	62,209	59,140	63,006
SC No 13TOD	Summer	24,340	23,966	23,079	23,622	20,692	24,340
	Winter	24,280	23,728	23,261	23,809	22,648	24,280
Gen Small	Summer	6,293	3,642	3,900	4,110	2,942	
	Winter	7,710	5,320	5,746	6,055	5,533	

Table M.3.B. Customer Class Loads in NYC (kW)

Class	Season	Non-Coincident Peak Demand	Half Hour Demand at Time of Class Peak, Unadjusted	Adjusted Demand at the Meter	Adjusted Demand at the Generator	System Peak Response	TOD Tariffs
Com Red	Summer	2,340	2,188	2,253	2,374	2,359	
	Winter	1,985	1,799	1,829	1,927	1,911	
Com RedTOD	Summer	119,269	111,925	111,367	114,334	113,300	119,269
	Winter	106,297	100,677	99,941	102,603	97,367	106,297
Traction	Summer	173,411	155,398	134,494	139,305	131,229	
	Winter	181,361	162,119	143,056	148,173	147,969	
ST LTG OTR	Summer	14,222	14,222	14,220	14,984	1,515	
	Winter	14,248	14,248	14,246	15,012	1,518	
Mult DW	Summer	163,462	156,642	163,685	172,361	149,612	
	Winter	128,351	119,848	124,718	131,329	124,991	
Mult DWTOT	Summer	58,464	56,435	55,224	58,192	52,355	
	Winter	38,180	36,797	36,295	38,246	36,842	
Gen LG	Summer	142,962	110,059	111,266	116,981	109,523	
	Winter	122,198	106,200	107,015	112,511	100,163	
Gen LG TOD	Summer	126,512	108,666	108,107	112,050	108,345	126,512
	Winter	94,275	77,533	77,070	79,881	74,767	94,275
ST LTG NYC	Summer	86,552	86,552	86,450	91,096	15,350	
	Winter	81,834	81,834	81,834	86,232	77,061	
Mult DWHG	Summer	1,118	1,068	1,115	1,175	1,071	
	Winter	1,182	1,138	1,198	1,262	1,208	
TA SUB	Summer	384,852	377,232	352,552	360,938	348,941	
	Winter	346,661	333,696	301,186	308,350	305,501	
NYC PUBBLG	Summer	467,212	408,105	410,263	432,155	382,426	
	Winter	280,627	244,625	250,008	263,349	204,417	
NYC PUBTOD	Summer	323,459	282,179	276,239	288,004	272,275	323,459
	Winter	252,828	221,483	220,692	230,091	215,861	252,828
EDDSPFJCON	Summer	57,822	48,054	48,647	51,233	49,238	
	Winter	54,241	44,671	45,244	47,650	39,177	
EDDSPFJTOD	Summer	188,123	165,790	164,051	170,771	168,686	188,123
	Winter	174,502	151,417	149,939	156,081	145,030	174,502
Total System	Summer	18,345,411	12,213,287	12,428,737	13,065,548	11,891,384	2,710,275
	Winter	13,948,087	8,403,863	8,549,089	8,982,332	8,043,628	2,132,159

Appendix N. Wind Generation Output Time-shift

Introduction

This appendix provides details about the rationale used to estimate potential to enhance the value of wind generation in New York using energy storage. It also includes important background information about the wind generation potential in New York.

The scenario developed for evaluation is intended to take advantage of wind resources and market conditions specific to New York. It exploits some compelling synergies between wind generation in New York, energy storage per se, and capacity needs in NYC which exist due to otherwise undesirable circumstances.

<u>The Proposed Value Proposition</u>

Off-peak production from upstate wind generation is sold – via a bilateral contract – to a LSE in NYC to charge storage in NYC. Electricity generated by wind farms during on-peak periods is sold directly via the grid at the prevailing zonal price (LBMP).

Relative to wind generation alone, the addition of storage allows for the following:

- Enhanced value of low value energy from wind generation that is produced off peak – most energy from upstate wind generation resources is available during times when demand and value are very or relatively low.
- Reduced importance/relevance of wind generation's "low" (10%) "effective capacity;" because wind energy is used to provide in-city storage capacity which has stable, predictable, controllable output. Also, wind generation still provides some capacity value, on-peak, upstate.
- A bilateral contract for off-peak wind generation reduces fuel price uncertainty for the electricity purchaser (LSE in NYC) and provides electricity revenue certainty for wind developers, hopefully providing internalizable risk reductions.
- Ability to avoid most or almost all congestion charges (relative to transmitting the energy to NYC when generated).
- Reduced minimum load violations (or the potential for them) because off-peak energy from wind generation is used to charge storage.
- Reduced thermal plant cycling during off-peak hours to accommodate fluctuations in wind generation output.
- Transmitting power (from upstate wind generation to NYC) when transmission losses are lowest.
- Reduced in-city air emissions (from generation).

Depending on the location, storage may also provide benefits associated with in-city reactive power/voltage stabilization, regulation, reserve capacity, and possibly improved power quality or distribution upgrade deferral.

Wind Generation in New York

The following draws heavily on the General Electric Wind Study (GE study) completed in March 2005.

GE Study Overview

The approach used for the GE study was to evaluate key processes affecting planning and operation of the New York State Bulk Power System (NYSBPS), across timescales from seconds to years. The study addresses the performance of the NYSBPS when accommodating a "high" penetration of wind generation.

Scenarios evaluated were intended to represent "severe, but likely tests of the operational impacts of significant amounts of wind generation."

Most technical analysis addressed four key topics:

- *Forecast Accuracy* – wind forecast accuracy affects NYISO unit commitment and operating reserve policies; related effects of wind generation forecasting accuracy were evaluated.

- *Wind and Load Variability* – intermittent wind generation adds to an already complicated balancing act performed by the NYISO between supply and demand. The GE study included an analysis of wind and load variability and the combined effect over three time scales: hourly, 5-minutes (load-following; economic dispatch), and seconds (regulation, AGC).

- *Operational Impact* – Grid operational impacts were evaluated for a system with and a system without wind generation (per the study scenario):
    - Simulation of statewide operations throughout a year addressed dispatch and unit commitment effects as a function of wind forecast accuracy.
    - "Quasi-steady-state" simulation of wind and load variation during representative three hour periods addressed load following implication.
    - Stability simulation of selected 10-minute periods, focusing on regulation and other short-term control and protection issues (voltage regulation, low-voltage ride-through, AGC, etc.)

- *Effective Capacity* – Wind generation's effective capacity was established, in part, by comparing it to performance of a typical fossil-fired power plant. The evaluation addressed seasonal and daily variability of wind generation output when system peak load occurs to assess the variability's impact on system reliability (loss-of-load probability (LOLP)).

Key results are summarized in Table N.1. that was excerpted from the GE report.

Table N.1. Summary of Key Analytical Results for the GE Study

Time Scale	Technical Issue	Without Wind Generation	With Wind Generation	Comments
Years	UCAP of Wind Generation	$UCAP_{land\text{-}based} \approx 10\%$ $UCAP_{offshore} \approx 36\%$ (one site in L.I.)		• UCAP is site-specific • Simple calculation method proposed
Days	Day-Ahead Forecasting and Unit Commitment	Forecasting error: $\sigma \approx$ 700-800 MW	Forecasting error: $\sigma \approx$ 850-950 MW	• Incremental increase can be accommodated by existing processes and resources in NY State • Even without forecasts, wind energy displaces conventional generation, reduces system operating costs, and reduces emissions. • Accurate wind forecasts can improve results by another 30%
Hours	Hourly Variability	σ = 858 MW	σ = 910 MW	• Incremental increase can be accommodated by existing processes and resources in NY State
	Largest Hourly Load Rise	2575 MW	2756 MW	• Incremental increase can be accommodated by existing processes and resources in NY State
Minutes	Load Following (5-min Variability)	σ = 54.4 MW	σ = 56.2 MW	• Incremental increase can be accommodated by existing processes and resources in NY State
Seconds	Regulation	225 to 275 MW	36 MW increase required to maintain same performance	• NYISO presently exceeds NERC criteria • May still meet minimum NERC criteria with existing regulating capability
	Spinning Reserve	1200 MW	1200 MW	• No change to spinning reserve requirement
	Stability	8% post-fault voltage dip (typical)	5% post-fault voltage dip (typical)	• State-of-the-art wind generators do not participate in power swings, and improve post-fault response of the interconnected power grid.

Note: σ = standard deviation

Wind Technology

Wind generation was assumed to be state-of-the-art with "continuously controllable reactive power capability (0.95 power factor at point of interconnection), voltage regulation, and low-voltage ride-through (LVRT)."

Wind Resource Overview

Most good wind resources for generation identified in the GE study are located upstate, in Zones A through E. For the scenario evaluated wind generation penetration is 23% of peak zonal load.

The study also identified 600 MW of offshore wind generation in Zone K which generates power equivalent to 11% of peak load in Zone K. The offshore wind generation was ignored for this evaluation because a) unlike upstate wind generation, output from offshore generation has a relatively good coincidence with load, and b) offshore wind development is less certain than land-based development.

Wind generation resources are summarized in Table N.2. Also shown are the portions of that potential evaluated – as if it is developed by 2008 – for the GE study. From Table N.2., about 2,700 MW of wind generation from upstate resources was the amount evaluated. As a point of reference, as of March 2005 the NYISO queue of proposed new generation presently has a total of 1,939 MW in wind projects, total.

Table N.2. GE Study Scenario – Wind and Load MW by Zone

	Total Potential Wind Generation	2008 Noncoincident Peak Load	Wind MW in Study Scenario	Wind as % of Peak Load
Zone A	3,070	2,910	684.2	24%
Zone B	1,197	2,016	358.5	18%
Zone C	1,306	2,922	569.7	19%
Zone D	483	902	322.6	36%
Zone E	2,832	1,592	399.8	25%
Zone F	434	2,260	260.6	12%
Zone G	105	2,260	104.6	5%
Zone H	0	972	0.0	0%
Zone I	0	1,608	0.0	0%
Zone J	0	11,988	0.0	0%
Zone K	600	5,275	600.0	11%
sum	10,026	34,704	3300.0	10%
DPS Zn 1	8,887	10,342	2334.8	23%
DPS Zn 2	538	7,099	365.2	5%
DPS Zn 3	600	17,263	600.0	3%
sum	10,026	34,704	3300.0	10%

Notes: DPS Zn 1 = Zones A + B + C + D + E
DPS Zn 2 = Zones F + G + H
DPS Zn 3 = Zones I + K

Notable Operational Considerations

Hour-Ahead Forecasting

NYISO updates load forecast hourly. Results of the forecast become inputs for the hour-ahead market process 75 minutes before the respective hour starts. Importantly for wind generation: "The hour-ahead market provides an opportunity to update and refine the wind forecast in parallel with the load forecast." Furthermore, "Hour-ahead wind forecasts significantly reduce the uncertainties associated with the day-ahead forecasts. On a system-wide basis, the wind forecast error…is reduced by 50% to 60%."

Wind Output Coincidence with Peak Load

An important finding from the GE study is that "the diurnal cycle of wind generation is generally opposite that of system load." As shown in Figure M.1., as demand rises during the morning, wind generation tends to decrease. This is important because without storage it is, to some extent, a disadvantage because a significant portion of energy is produced when not valuable. With storage "off-peak" energy production may actually be advantageous because it can be moved to NYC when transmission losses and congestion are low, not to mention the added benefit when the energy is discharged.

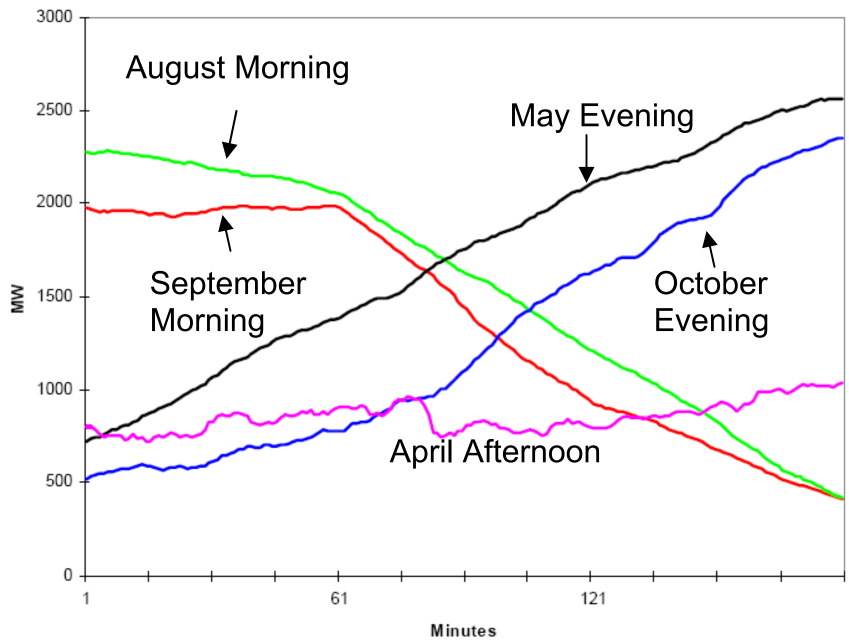


Figure N.1. Wind Generation Output – Mornings and Afternoons, Various Months

Effective Capacity of Wind Generators

The study included an estimation of wind generation's "effective capacity" – the amount which the NYISO can treat as if it were "firm" capacity. (In New York, the effective capacity is equivalent to "UCAP.") Specifically, wind generation's effective capacity was estimated using its *energy* capacity factor during the four-hour peak load period (1:00pm to 5:00pm) in the summer months. According to the GE study authors: "This method produces results in close agreement with the full LOLP analytical methodology."

Based on results from the GE study; annual capacity factors for wind generation located in western upstate New York are about 30% of turbines' rated capacity. However, aggregated wind generation's effective capacity is about 10%. The difference is due to seasonal and, more importantly, daily discontinuities between energy use and wind patterns (and thus wind generation output). Upstate wind generation is "largely 'out of phase' with the NYISO load patterns."

Offshore wind generation in Long Island has an effective capacity of about 40%. The higher value (relative to upstate resources) relates to daily wind patterns which result in generation that is much more coincident with peak demand.

Capacity factors from the GE study are based on meteorological data for years from 2001 through 2003 and on operating characteristics of GE's 1.5 MW wind turbine. The authors note that they expect future wind turbine designs to "show greater efficiencies with corresponding increases in effective capacities."

Transmission Congestion and Production Cost Implications

Most New York wind generation potential is located upstate, so adding wind generation increases transmission flows from the upstate area to the downstate area. Figure N.2. shows a simulated time-duration curve of the UPNY-SENY (upstate New York to Southeast New York) interface flow for year 2008, with and without wind generation per the study scenario.

Without wind generation, interface flow is at its limit for approximately 1,100 hours during the year. Wind generation increases the number of hours at limit to 1,300. So "the number of hours that the UPNY-SENY (upstate New York to Southeast New York) interface was limiting increased roughly 200 to 300 hours in the cases with the wind generation present." Conversely, most of the increased flows occurred during times when transmission is not heavily loaded.

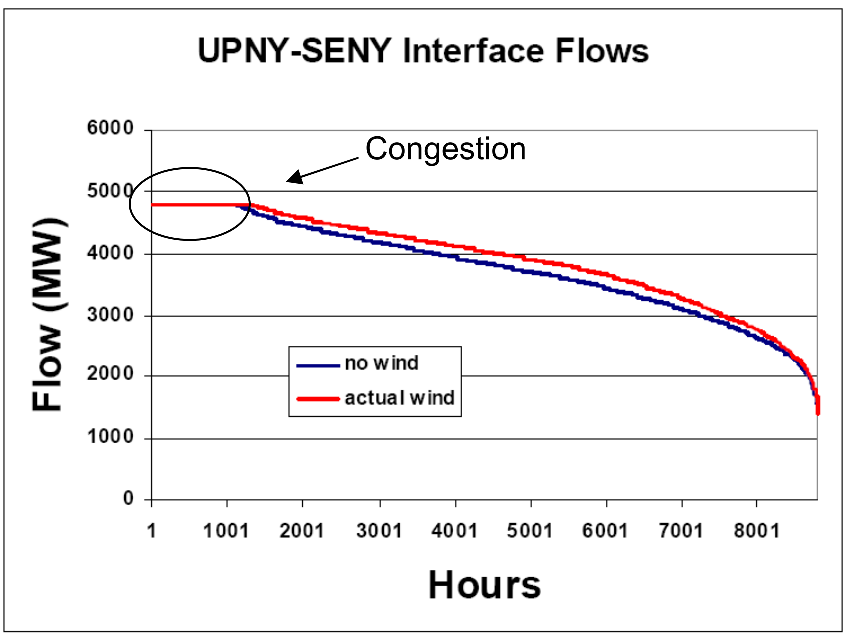


Figure N.2. Wind Generation Increases Transmission Congestion

Another measure of congestion evaluated for the GE study was local spot price. Specifically, the evaluation addressed the possibility that significant amounts of wind generation during hours when the system-wide load is low could lead to "minimum load" problems (also known as minimum load violations).

That could lead to reduced use of otherwise competitive generation – mostly thermal or hydroelectric generation and in some cases may actually result in “dumping” of “excess” energy. The result is a rise in location marginal price.

The key to minimizing locational energy price increases due to wind generation seems to be the ability to “accurately forecast the wind generation for the day ahead market” which “can greatly enhance” wind generation’s value. The existing forecast accuracy seems to be quite good though improvements could add about $1.50/MWh to the value of wind generated electric energy.

<u>Key Conclusions with Possible Implications for Energy Storage</u>

Existing NYISO operating practices account well for uncertainties in load forecast. The incremental uncertainties due to imperfect wind forecasts are not expected to impact the reliability of the NYSBPS.

An addition of 3,300 MW of wind generation could lead to a reduction of zonal spot prices by “a few percent to as much as 10%.” The use of wind generation could also reduce sulfur oxides (SOx) emissions in New York by 5% and nitrous oxides (NOx) emissions by 10%.

Importantly, accurate forecasting allows cost-effective accommodation of additional wind generation. Specifically, “day ahead forecast accuracy is fairly high when viewed across a projected 3,300 MW of wind capacity spread across the state.”

Wind turbines in upstate locations generate about 30% of the year (full output equivalent); though, the NYISO can only depend on effective capacity of 10%, due in part to discontinuities between daily wind generation (land-based, upstate) and electricity demand.

If an excess of wind power causes the NYISO to decommit important thermal generators with long start-up times, the system could become less reliable.

The electricity marketplace in New York should be structured so wind generators have “clear financial incentives to reduce output when energy spot prices are low” while the NYISO “must have the capability to limit or curtail power from wind generators when necessary for system reliability reasons.”

To accommodate 3,300 MW of wind generation, approximately 36 MW (3σ) of additional regulation capacity is needed. However, the NYSBPS could possibly meet minimum NERC (regulation) requirements with no increase in regulation capacity.

UCAP ratings for wind generation must be established differently than that for conventional generation because wind generation is intermittent. But, the way wind generation participates in the UCAP market should be exactly the same as that for all other generation.

Wind Plus Energy Storage Value Proposition

Key Assumptions

Wind generation cost is about 6.2¢/kWh including capital carrying charges for a plant costing $1,000/kW, installed and with variable operating cost of 1/2¢/kWh.[2]

The wind plants operate at 30% annual capacity factor (2,628 hours/year) and provide 10% effective capacity, on-peak, in upstate zones. The value of capacity is assumed to be $25/kW year and the wind generation is assumed to receive 10% of that, or $2.5/kW-year.

About 55% of the wind energy (1,445 hours per year) – generated off-peak – is sold via bilateral contracts to an LSE in NYC to charge a five hour storage plant. The LSE buys 8% extra energy to makeup for T&D losses. The contract price is 6.25¢/kWh. The balance of energy from the wind turbine is sold via the grid, at the prevailing LBMP, assumed to be 6.25¢/kWh, on average (generation is sold mostly during mid and on peak price periods).

The energy storage system has 80% round trip efficiency and a variable operating cost of 5¢/kWh_{out}. The battery plant discharges 260 times per year (weekdays) during five peak load hours. About 82% of the energy stored throughout the year is from wind generation and the balance comes from the grid.

The avoided in-city on-peak energy purchases are assumed to cost an average of 15¢/kWh or $195/kW-year. Assuming an in-city UCAP value of $140/kW-year (~$12/kW-month) and a 75% effective capacity credit for the storage (that discharges on-peak, 1,300 hours per year), the storage receives a capacity credit of $105/kW-year.

Results

Assumptions and calculations are shown in the worksheet below. Storage cost, including variable operating cost and charging energy cost, is estimated to be $179.3/kW-year. Gross benefits include the value of the energy that is discharged plus the capacity credit, or $300/kW-year. The net benefit is the difference, or $116/kW-year. That is the amount that would be available to cover capital carrying charges for the storage plant.

Wind Generation

Financials

Capital Plant Cost Annualization Factor	0.15	Used to calculate annual capital plant carrying charges from the installed cost. Includes Return of Principal, Interest and/or Dividends, Income Taxes, Property Tax, Insurance.

Wind Generation Cost and Production

Capacity Factor	0.3	Full Load Hours	2,628	
Installed Cost ($/kW)	1,000	Carrying Charges ($/kW-year)	150.0	5.7¢/kWh
Variable Operating Cost -- VOC (¢/kWh)	0.5	Annual VOC ($/kW-year)	13.1	
		Annual Cost ($/kW-year)	**163.1**	**6.2¢/kWh**

Bilateral Contract (to Storage, in NYC)

Portion of Annual Production Sold Bilaterally	55.0%	Annual Full Load Hours	1,445
Price (¢/kWh)	6.25	Revenues ($/kW-year)	90.3

Real-time Sales

Energy Sell Price (¢/kWh)	6.25	Portion of Annual Electricity Generation Sold Via Grid	45.0%	
Full Capacity Credit* ($/kW-year)	25	Annual Full Load Hours	1,183	
*For qualifying generation adjusted for forced outages.		Energy Revenues ($/kW-year)	73.9	
Effective Capacity (% of nameplate)	10.0%	Capacity Revenues ($/kW-year)	2.5	
		Annual Revenue ($/kW-year)	**166.8**	**6.3¢/kWh**

Storage

Cost and Production

Storage Variable Operating Cost (¢/kWh)	5	Annual VOC ($/kW-year)	65.0	
Storage Discharge Duration (hours)	5	Annual Full Load Discharge Hours	1,300	
Storage (Round-trip) Efficiency	80.0%	Annual Energy Losses (kWh)	325	
Storage Annual Discharges (full)	260	Annual Charging Energy (kWh)	1,625	
		Ann. Wind Energy Purchased (kWh)	1,445	
Allowance for Transmission Losses	8.0%	Annual T&D Energy Losses (kWh)	-116	
		Ann.Wind Energy into Storage (kWh)	1,330	
		Portion of Wind Energy into Storage (%)	81.8%	
Transmission Service Charge (¢/kWh)	0.3	Transmission Cost ($/kW-year)	4.3	
Grid Charging Energy Price (¢/kWh)	8	Wind Energy Cost ($/kW-year)	90.3	
Grid Energy into Storage (kWh)	300	Grid Energy Cost ($/kW-year)	24.0	
Grid Energy Portion of Total Energy into Storage	18.5%	Annual VOC ($/kW-year)	65.0	
		Annual *Operating* Cost ($/kW-year)	**183.7**	**14.1¢/kWh**

Benefit

Avoided Energy Purchases Price (¢/kWh)	15			
Full Capacity Credit* ($/kW-year)	140	Avoided Annual Energy Purchases ($/kW-year)	195.0	
*For qualifying generation adjusted for forced outages.				
Effective Capacity** (% of nameplate)	75.0%	Capacity Credit ($/kW-year)	105.0	
**Relative to proxy with "very constant and reliable" output.		**Annual Gross Benefit ($/kW-year)**	**300.0**	**23.1¢/kWh**
		Storage Annual Net Benefit ($/kW-year)	**116.3**	**8.9¢/kWh**

Primary References

[1] Saintcross, John, Senior Project Manager. The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations; Phase 2, System Performance Evaluation. Prepared for the New York State Energy Research and Development Authority. Albany, NY. Prepared by GE Energy, Energy Consulting. March 4, 2005.

[2] Makhijani, Arjun. Bickel, Peter. Chen, Aiyou. Smith, Brice. Cash Crop on the Wind Farm: A New Mexico Case Study of the Cost, Price, and Value of Wind-Generated Electricity. Prepared by the Institute for Energy and Environmental Research for presentation at the North American Energy Summit Western Governors' Association Albuquerque, New Mexico, April 15-16, 2004. Page 16.

Appendix O. PV Capacity Firming Using Electricity Storage

This appendix includes details about the PV capacity firming application benefit calculations and assumptions.

Worksheet

The worksheet used to estimate capacity firming benefits for photovoltaics, including all assumptions, is shown below.

Storage			Benefit Summary	($/kW-year)	
Efficiency	80%		PV Only	336.5	
Variable Operating Cost (¢/kWh_{out})	4.0		Storage Increment	39.8	11.8%
Storage Discharge Duration (hours)	2.5				

Summer 2006

Grid

Peak Days per year (season)	130	Grid Energy Price Off-Peak (¢/kWh)	8.0	
Peak Hours per day	5.0	Mid Peak (¢/kWh)	10.0	
Capacity Value ($/kW for 6 months)	72.0	On-Peak (¢/kWh)	16.0	

Photovoltaics

Seasonal Availability	42.0%	Seasonal Full Load Hours	1,840	
Average Energy Value (¢/kWh)	11.0	Energy Value ($/kW-year)		202.4
Effective Capacity (w/o firming)	0.50	Capacity Credit ($/kW, for 6 months)		36.0
		Total Benefit		**238.4**

Storage

		Default			
			Full Load Output with Storage	2,165	
Solar Hours/Day Shifted To Peak*	0.0	2.5	Hours from Storage	326	
*Net of storage losses.			On-Peak Energy Sales Benefit ($/kW-year)		0.0
			Reduced Mid Peak Sales ($/kW-year)		n/a
Hours/Day Output from Grid Energy	default	2.5	Sell Off-peak Energy On-Peak ($/kW-year)		52.1
Hours/Day Charging from Grid Energy	3.1		Off-peak Grid Energy Charging ($/kW-year)		-32.6
Firmed Capacity	0.95		Increased Energy Value ($/kW-year)		19.6
			Increased Capacity Value ($/kW-year)		32.4
			Storage VOC ($/kW-year)		-13.0
			Storage Incremental Benefit ($/kW-year)		**38.9**

Winter 2006

Grid

Peak Days per year (season)	130	Grid Energy Price Off-Peak (¢/kWh)	6.0	
Peak Hours per day	5	Mid Peak (¢/kWh)	9.0	
Capacity Value ($/kW for 6 months)	30.0	On-Peak (¢/kWh)	12.0	

Photovoltaics

Seasonal Availability	25.0%	Seasonal Full Load Hours	1,095	
Average Energy Value (¢/kWh)	8.0	Energy Value ($/kW-year)		87.6
Effective Capacity (w/o firming)	0.35	Capacity Credit ($/kW, for 6 months)		10.5
		Total Benefit ($/kW-year)		**98.1**

Storage

		Default			
			Full Load Output with Storage	1,421	
Solar Hours/Day Shifted To Peak*	0.0	2.5	Hours from Storage	326	
*Net of storage losses. Cannot exceed that for Summer.			On-Peak Solar Energy Sales ($/kW-year)		0.0
			Reduced Mid Peak Sales ($/kW-year)		n/a
Hours/Day Output from Grid Energy	default	2.5	On-Peak from Grid Energy ($/kW-year)		29.3
Hours/Day Charging from Grid Energy	3.1		Off-peak Grid Energy Charging ($/kW-year)		-24.4
Firmed Capacity	default	0.65	Increased Energy Value ($/kW-year)		4.9
			Increased Capacity Value ($/kW-year)		9.0
			Storage VOC ($/kW-year)		-13.0
			Storage Incremental Benefit ($/kW-year)		**0.9**

Production

Annual Energy PV Only (kWh/year)	2,935	Annual Energy Output with Storage (kWh/year)	3,586
Capacity Factor	0.335	Capacity Factor	0.409

Relevant Research Findings

The following are excerpts documented in the two research papers (references 3 and 4) which summarize findings from cutting edge research undertaken in conjunction with the National Renewable Energy Laboratory (NREL). The objective was to determine how the value of customer-sited PV can be increased with battery storage by enhancing the load management and outage protection attributes of PV.

Case studies in San Jose, CA and Long Island, NY for residential and commercial PV applications are used for a quantitative illustration of storage value enhancement. Results indicate that: (1) a small amount of storage for local load control and a larger amount of storage for emergency load protection significantly increases the value of distributed PV to the customer; (2) the value of PV combined with emergency storage exceeds the sum of the value of these options implemented separately; and (3) there is a potential opportunity to use dispersed PV + storage to enhance grid security (capturing this value, however, will require regulatory and policy changes).

The case studies clearly show that the addition of a small amount of storage for local load control, and a larger amount of storage for emergency load protection are beneficial to the economics of customer-sited PV. The results obtained for emergency storage are, of course, dependent upon the [customer-specific] value…for critical load protection…, and upon the willingness of prospective PV owners to account for this factor in their planning [and/or financial evaluations].

High visibility events, such as the August 14th, 2003 northeast blackout, which are a reflection of increased demand/transfer stress on the aging power grid infrastructure, and an increasing concern for severe weather and terrorism disruptions, should highlight the need for some form of insurance and foster the development of and incentives for PV + storage installations instead of PV alone.

The results also suggest that the UPS market where customers have already made the choice of purchasing load protection insurance via energy storage may be an attractive near-term target for PV developers. Adding a PV installation to a planned UPS is a very attractive option because of the synergy observed between PV and storage.

Results indicate the existence of a potential opportunity for utilities and grid-operators to use dispersed PV + storage installations to enhance grid security through dispersed, immediately dispatchable emergency generation. The value of this PV + storage option will only be fully quantifiable when utility-to-customer business protocols are defined and made operational.

Specifically, for commercial customers, the probability of summer peak load reduction with PV alone is 40%. With two PV-hours of load management [batteries], peak load reduction probability is increased to 100% of installed PV capacity.[4].

References

[1] Union of Concerned Scientists. *Million Solar Roofs Bill Passes Senate--Faces Serious Challenges in State Assembly*. June, 15, 2005. http://ucsaction.org/campaign/6_15_05_solar_roof_CA

[2] Environment California. *w* web page. http://environmentcalifornia.org/envirocaliftoxics.asp?id2=13122

[3] Hoff, Thomas E. Perez, Richard. Margolis, Robert M. Increasing the Value of Customer-Owned PV Systems Using Batteries.November 2004. http://www.clean-power.com/research/customerPV/OutageProtection.pdf

[4] Hoff, Thomas E. Perez, Richard. Margolis, Robert M. Increasing the Value of Customer-Owned PV Systems Using Batteries and Controls. August 2005. http://www.clean-power.com/research/customerPV/OutageProtection_ASES_2005.pdf

Appendix P T&D Deferral Background

This appendix provides background regarding the cost calculation used to estimate T&D upgrade deferral.

The concept is straightforward: for a T&D node that is at or near full load during peak demand periods storage located downstream (electrically) from overloaded equipment can, in theory, carry peak load such that the T&D upgrade is deferrable.

A key premise regarding the T&D deferral benefit is that the maximum value is the annual revenue requirement for new T&D equipment. The revenue requirement includes utility cost of capital (dividends plus interest), return of capital (principal), income tax, property tax, and insurance.

As the logic goes: ratepayers would prefer alternatives that deliver the same “utility” as the upgrade, for one year, at lower cost. (This also assumes that utility stockholders and bondholders are made whole; all dividend, interest, and return of capital payments must be covered by utility revenue requirements.)

Notably, annual revenue requirements for deferred T&D upgrades are treated as if they are avoided “forever” if the upgrade is indeed deferred.

Consider an example: 200 kW storage costing $80,000 for one year can be used to defer an T&D upgrade whose annual revenue requirement is $100,000. Assuming that storage and the upgrade are comparable solutions – to serve load growth for the next year – then the benefit for using storage is $100,000. Netting out $80,000 annual cost for the storage leaves a single year net benefit of $20,000 in the form of cost reduction for ratepayers.

Note this is a single year benefit. If the T&D upgrade is deferred for two years then the benefit is the annual revenue requirement for two years, less discounting for the second year to account for time value of money.

Annual Cost for T&D Upgrades

So revenue requirement is the maximum benefit associated with deferring the upgrade for one year. That represents the annual cost for the utility to own one kW of T&D capacity “on the margin” for one year. (Operating costs avoided are assumed to be negligible.) To generalize benefits for T&D deferral the annual utility benefit must be expressed in units of $/kW *of storage* per year.

Those annual values – in units of $/kW-year of storage – are estimated as described below.

Annualization Factor – Fixed Charge Rate

The first step in the process is to calculate the annual revenue requirements. That is done using an annualization factor or fixed charge rate. The fixed charge rate is a function the elements of utility annual revenue requirement (cost of capital, return of capital (principal), etc.) When total installed cost for a T&D upgrade is multiplied by the fixed charge rate the result is the annual “levelized” revenue requirement; the amount that is assumed to be the single year benefit, if storage is used to defer the upgrade.

Based on the prevailing “Rate Case” for Con Edison (Effective March 15, 2005 in Case 04-E-0572) authors have determined that .1395 is the appropriate fixed charge rate for T&D facilities.

From page 139 of the rate case: "The revenue requirement impact will be calculated by applying an annual carrying charge factor of 13.95 percent (representing a combination of pre-tax rate of return of 11.40 percent and depreciation of 2.55 percent) to the actual Rate Year variance from the T&D Capital Target."

T&D Upgrade Cost

The cost for T&D upgrades varies considerably depending on several factors, especially 1) the type of upgrade, 2) the amount of capacity to be added (upgrade factor), and 3) the location. Lower cost upgrades may involve modest changes to substation transformers or feeders or may involve expensive upgrades to substations (including upsizing or adding transformers) and including underground cables.

One indication of the average cost per kW is use of FERC Form 1 information. It reflects information that large utilities – including Con Edison – must file with FERC regarding matters that include capital spending. FERC Form 1 data for Con Edison is shown below.

Table P1. Con Edison FERC Form 1 T&D Additions Data

Consolidated Edison Distribution Plant Additions
Source: FERC Form 1

Load, 2002	13,065	Equipment Value ($Current)	5,681,749,299
Load Growth Rate	2.0%	T&D Equipment Life Years)	30
Annual Load Growth	261	Annual Replacement Cost ($Current)	189,391,643
		Inflation	2.5%
		Present Worth Factor* *Accounts for inflation over 30 years.	1.5
		($2004)	284,087,465

FERC Form 1 Accounts Accounts	Beginning Balance Q1/2002	Additions Each Year 2002	2003	2004	Average 2002 - 2004
(360) Land and Land Rights	26,994,288	0	42,687,556	6,711,613	16,466,390
(361) Structures and Improvements	127,897,087	5,714,974	15,758,958	65,617,548	29,030,493
(362) Station Equipment	947,267,527	52,149,693	88,368,207	114,010,064	84,842,655
(364) Poles, Towers, and Fixtures	243,680,773	6,649,944	5,166,380	15,107,401	8,974,575
(365) Overhead Conductors and Devices	399,684,778	15,862,630	14,927,932	21,784,476	17,525,013
(366) Underground Conduit	1,506,782,711	85,517,451	117,692,596	132,176,478	111,795,508
(367) Underground Conductors and Devices	2,429,442,135	103,907,620	100,840,500	200,648,122	135,132,081
Total	**5,681,749,299**	**269,802,312**	**385,442,129**	**556,055,702**	**403,766,714**

Average Annual Distribution Budget	403,766,714
Estimated Amount for Replacement Cost	284,087,465
Estimated Amount for Growth	119,679,249
Annual Load Growth (MW)	261
(kW)	261,300
$/kW of load growth	458

To estimate that value divide the value of the existing distribution equipment by 30 – the equipment is assumed to have a 30 year life. From the worksheet above; the existing plant is about $5.7 Billion. Dividing that by 30 indicates that about $190 Million / year could be attributed to replacing worn out equipment. However, that value reflects “current” dollars. To convert that value to reflect “replacement” cost the current dollar value is adjusted for inflation (during the 30 years). When adjusting the $190 Million / year current dollar value the replacement cost ($2002) is about $284 Million.

From the table, the average annual spending for distribution equipment is about $400 Million. After subtracting the $284 Million for replacement cost the balance – $119 Million – is assumed to be for load growth. Finally, after dividing load growth into that value the system wide average cost to serve new load is an estimated $458/kW.

To be clear, that value represents the average cost to accommodate another kW on the margin in the distribution system. In reality, there probably are no specific projects with that cost; instead some projects cost more and others less. In fact, in many locations the cost to accommodate additional load is zero (those are locations where there is plenty of existing distribution capacity). In many other locations modest upgrades or equipment adjustments will accommodate new load. It is the expensive projects – on a $/kW basis added – that are attractive candidates for deferral.

Note also that that value is for the entire Con Edison service area. In-city values may be higher.

T&D Upgrade Annual Revenue Requirement

The fixed charge rate is used to calculate the annual revenue requirement for a T&D project. For example, a 12MW T&D node will be upgraded to carry 15 MW of load, an increase of 3 MW. If the project costs $450 per kW added the total project cost is 1.35 Million. When applying a fixed charge rate of .1395 the annual revenue requirement is $1,350,000 * .1395 = $188,000/year ($62.8/kW-year).

T&D Equipment Salvage Value

Often when equipment is upgraded it can be re-used. This is especially important for transformers. When a substation is upgraded and a transformer is taken out of service as a result it is returned to rotating stock if it has useful life remaining.

Storage Sizing for T&D Deferral

Storage Power Output Requirements

Deferring an upgrade for one year requires energy storage whose power output is equal to the expected load growth plus necessary and prudent allowance for uncertainty, primarily: a) load growth that exceeds expectations and b) storage reliability.

Consider the example illustrated in Figure P1. Assume that the distribution node being evaluated is currently rated at 9 MW[2] and that load growth on the circuit occurs at about 2.0% per year.

Furthermore, as shown in the figure, at the end of 2007 loading will equal the distribution equipment's load carrying capacity. During the year 2008 load growth is expected to be 9 MW *0.02 = 180 kW.

[2] Readers should note that units of kW and MW (apparent power) are used herein, rather than the more technically correct true power (kVA and MVA). However, assuming a high power factor, this will not change results much. If necessary, kW and MW values should be adjusted to account for power factor, in any given circumstance.

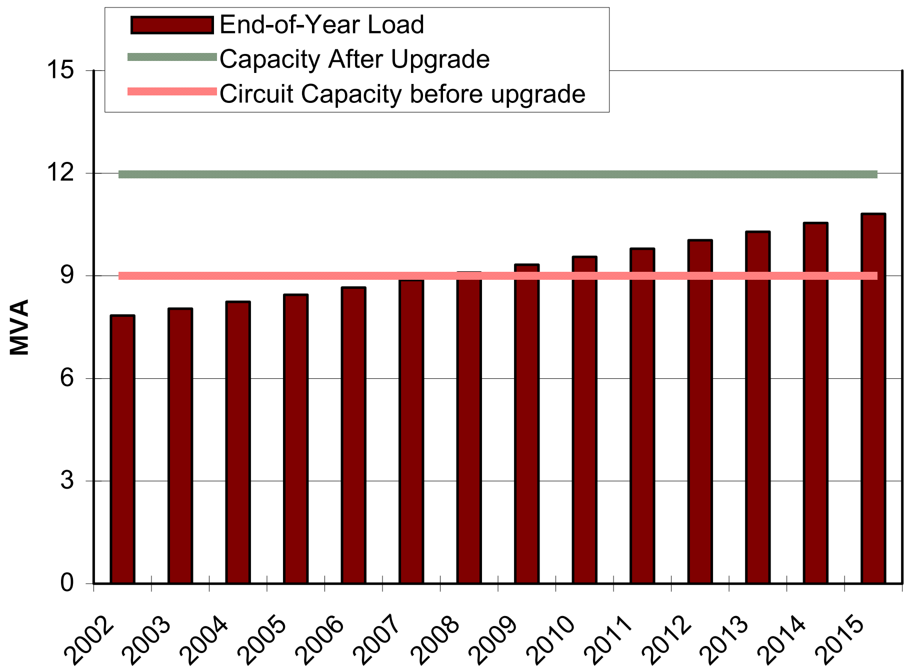


Figure P1. Distribution Peak Load, Capacity, and Upgraded Capacity

In theory, if the load growth projection is precise a storage plant rated at 180 kW could meet load growth in 2007. If so, the utility could defer the distribution upgrade for one year.

Of course, an engineering contingency may be in order. That is, if power engineers believe that there is an unacceptable chance that load growth may exceed 180 kW then the storage power rating may have to be higher than 180 kW.

Storage Discharge Duration Requirements

Discharge duration is the amount of time that the storage plant must discharge at full power. Ideally, measured, time-specific demand data can be used to make the estimate. The hourly load profile for the day with the highest measured demand is isolated from the load data. Ideally that is done for several years to locate the profile with the "widest" peak. Or, some utilities have design load profiles.

No matter how the profile is produced; the maximum load on the day represented by the profile is treated as if it is the maximum rated (nominal) capacity of the distribution system node being evaluated. When load growth for a single year is added to that day's load, by definition, the top of the modified load profile exceeds the demand ceiling.

This process is illustrated graphically in Figure P2. In that figure the upper left chart shows load in "year 0," the year before the distribution capacity is expected to be loaded up to its rating. The lower right chart shows load after one year of load growth. The darker portion of bars – for hours 18 and 19 in that day – indicate that the load is exceeding the rating of the 9 MVA circuit.

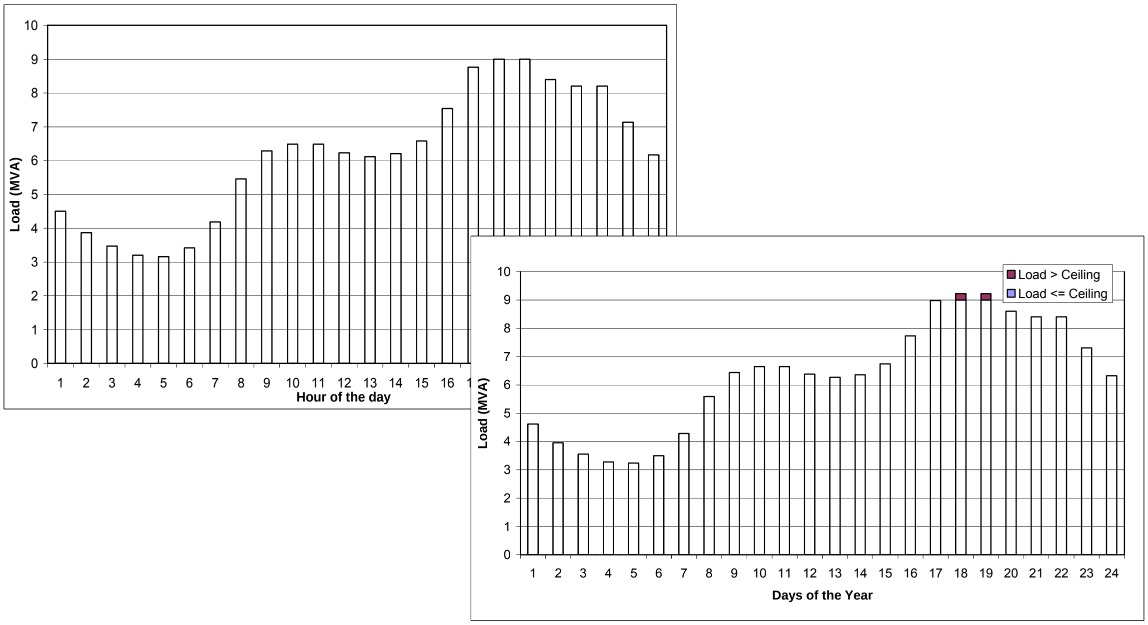


Figure P2. Storage Sizing to Meet Peak Demand:
Energy Requirements for a Single Year's Load Growth

The number of hours during which load exceeds the demand ceiling defines the storage discharge duration. Even if the load ceiling is exceeded by just a small margin during a specific hour of the day, an entire hour of "full load" discharge is assumed to be required for the storage plant. This is intended to reflect conservative engineering design.

In the example in Figure P2, 2.0% load growth (180 kW) is added to the "year 0" demand profile. The result is that load, in "year 1" exceeds the demand ceiling on the distribution node for two hours. That is assumed to be the minimum storage duration required, for this example. When addressing uncertainties it may be prudent to make the discharge duration longer; perhaps three hours is a safe discharge duration in this example.

For more details readers are encouraged to refer to a report developed by Sandia National Laboratories entitled Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral, a Study for the DOE Energy Storage Program. Sandia National Laboratories, Energy Storage Program, report #SAND2005-7069.

Single Year Deferral Benefit

This section illustrates the calculation used to estimate the deferral benefit for storage. Continuing with the examples above the expected load growth is 180 kW and engineers want to use a 250 kW storage system to serve that expected load. So a $1,350,000 upgrade can be deferred for one year. The revenue requirement that is not paid – that is avoided – is $188,000/year. $188,000/year ÷ 250 kW of storage = $752/kW of storage *for one year*.

Multi-year Deferrals

Though it is easy to imagine situations for which a T&D upgrade may be deferred for more than one year – using modular resources like storage – often deferrals are feasible for just one or two years. The reason is that more and more storage (power and energy) must be added to accommodate load growth. Consider the example above: peak load growth in year 1 is 2% of 9 MW or 180 kW. Peak load growth in year 2 is 2% of 9.18 kW or 184 kW. So, in year 2 cumulative load growth is 364 kW. Assume that engineers specify 500 kW of storage to defer the upgrade for a second year (from above, 250 kW was needed in year 1).

From the example in the previous section, the annual revenue requirement for the deferral (without regard to time-value of money) is the same $188,000 as in year 1. So, the single year deferral benefit for the 500 kW storage plant in year 2 is $188,000/500 kW = $376/kW. Compare that to the first year deferral benefit (calculated in the previous section) of $752/kW.

Appendix Q. Regulation Benefit Details

Regulation Using Storage - An Introduction

The Regulation and Frequency Response (regulation) ancillary service provides the means to balance supply resources and customer demand. The NYISO controls operation of resources that provide the regulation – usually generation. The NYISO offers this service to transmission owners/operators who may purchase that service or may make alternative comparable arrangements.

For generators to provide regulation variation of plant output above and below a base operating point, energy supplied at the generator's base operating point is not part of the regulation provided. In fact, the energy output associated with regulation nets out to zero over a timescales of several hours as the generator output varies, between being above and being below its base operating point.

One advantage of storage for regulation is that it can be dedicated to supplying regulation without the need to also supply energy, like generation does. This is because storage can "absorb" energy (charging) and "inject" energy (discharging). The effect is that storage can act as a load sometimes and like generation at other times. Energy lost during the charge/discharge cycle is purchased at the prevailing market rate.

ISO Regulation Tariff - Rate Schedule 3

<u>ISO Responsibilities</u>

(a) Establish requirements consistent with the Reliability Rules
(b) Provide RTD Base Point Signals (5 min) and AGC Base Point Signals (6 sec)
(c) Qualify generators
(d) Establish metering telecommunications requirements
(e) Select Generators for Day-Ahead Market and Real-Time Market
(f) Pay Suppliers
(g) Monitor performance

<u>Supplier Responsibilities</u>

(a) Offer only committed generators able to respond to AGC Base Point Signals
(b) Pay any charges imposed
(c) Ensure selected generators comply with Base Point Signals and ISO Procedures

<u>Selection of Suppliers in the Day-Ahead Market (DAM) and the Real-Time Market</u>

(a) ISO evaluates bids and selects suppliers
(b) ISO establishes market clearing prices

Supplier Bids Include

- Capability (in MW) that the generator is willing to provide
- Regulation response rate (MW/min)
- Bid Price (in $/MW)
- Physical location and name of the Generator

DAM Settlements

- ISO calculates Day-Ahead Market clearing price for each hour
- Each scheduled (winning) supplier is paid the clearing price in each hour, multiplied by the scheduled amount

2. Sample DAM Prices

- See table Q.1., below
- Regulation Services have the highest prices among reserve products
- East and West pricing is the same

Table Q.1. Ancillary Services Prices, Day Ahead Market, 03/31/2006 ($/MWh)

	East				West			
Time Stamp	10 Min Spinning Reserve	10 Min Nonsynch Reserve	30 Min Operating Reserve	Reg Reserve	10 Min Spinning Reserve	10 Min Nonsynch Reserve	30 Min Operating Reserve	Reg Reserve
3/31/2006 0:00	2.49	2.49	0.25	43.00	0.25	0.25	0.25	43.00
3/31/2006 1:00	2.99	2.99	0.25	43.00	0.25	0.25	0.25	43.00
3/31/2006 2:00	0.25	0.25	0.25	43.00	0.25	0.25	0.25	43.00
3/31/2006 3:00	0.25	0.25	0.25	43.00	0.25	0.25	0.25	43.00
3/31/2006 4:00	2.99	2.99	0.25	43.00	0.25	0.25	0.25	43.00
3/31/2006 5:00	3.27	2.99	0.99	93.54	3.27	2.99	0.99	93.54
3/31/2006 6:00	0.84	0.84	0.25	112.77	0.25	0.25	0.25	112.77
3/31/2006 7:00	7.00	0.25	0.25	103.05	7.00	0.25	0.25	103.05
3/31/2006 8:00	13.08	0.25	0.25	80.00	13.08	0.25	0.25	80.00
3/31/2006 9:00	17.06	2.69	0.99	80.00	15.36	0.99	0.99	80.00
3/31/2006 10:00	17.88	1.00	0.99	80.00	17.87	0.99	0.99	80.00
3/31/2006 11:00	17.13	0.99	0.99	53.13	17.13	0.99	0.99	53.13
3/31/2006 12:00	9.49	2.99	0.99	43.49	7.49	0.99	0.99	43.49
3/31/2006 13:00	9.49	2.99	0.99	43.49	7.49	0.99	0.99	43.49
3/31/2006 14:00	9.19	2.69	0.99	43.49	7.49	0.99	0.99	43.49
3/31/2006 15:00	9.19	2.69	0.62	43.12	7.12	0.62	0.62	43.12
3/31/2006 16:00	7.34	0.84	0.50	98.16	7.00	0.50	0.50	98.16
3/31/2006 17:00	7.34	0.84	0.84	99.28	7.34	0.84	0.84	99.28
3/31/2006 18:00	14.48	0.99	0.99	80.00	14.48	0.99	0.99	80.00
3/31/2006 19:00	16.18	0.99	0.99	74.00	16.18	0.99	0.99	74.00
3/31/2006 20:00	15.06	0.99	0.99	80.00	15.06	0.99	0.99	80.00
3/31/2006 21:00	7.49	0.99	0.99	84.34	7.49	0.99	0.99	84.34
3/31/2006 22:00	7.00	0.25	0.25	85.45	7.00	0.25	0.25	85.45
3/31/2006 23:00	0.39	0.39	0.30	74.00	0.30	0.30	0.30	74.00

3. Study Approach

Day Ahead Market

Benefits will be calculated under the Day Ahead Market. While Real Time Market is also a prospective application for storage, the analysis is complicated since historical AGC Base Point signals are not available. These signals would indicate how the storage system would be dispatched in each 6-second interval, and consequently the ISO payments. On the other hand, payments in the DAM are made based on hourly commitment.

System Ratings

The storage system is assumed to be sized with adequate energy storage to meet the charge and discharge requirements under AGC.

Operation and Setpoint

A signal is sent from the ISO to indicate the MW output of generators (always positive). In the case of storage, a “setpoint” would be defined to correspond with a zero signal, and this would correspond with the necessary charging power to allow the system to discharge (or charge at lower rate) in response to changes in the signal. For example, if the setpoint were -2 MW (charging at 2 MW), and the AGC required 3 MW of generation, the storage system would discharge 3 – 2 = 1 MW over the required interval.

Costs

This analysis only considers benefits. Operating costs, including capital recovery costs, O&M costs, and charging energy costs, are not included. However, since the ISO will only schedule suppliers with acceptable bids, the storage system must have costs low enough to offer successful bids. For this analysis, operating costs are reported in *$/MW per hour of regulation service*. This is not the same as $/MWh since the system is not dispatched at full power for the full hour. Rather, the system is committed for service during the hour, during which time it charges and discharges up to the full power rating.

Dispatch Model

Hourly clearing prices ($/MWh) for 2005 were obtained from the NYISO. This data is shown in Figure Q.1. For each hour, the assumed operating cost is compared with the clearing price. The system is assumed to operate only during hours in which its operating costs are at or below the clearing price. When this condition is true, the system is scheduled for dispatch, and the full hourly value is obtained.

4. Statistical Data

Hourly pricing data downloaded from http://www.nyiso.com.

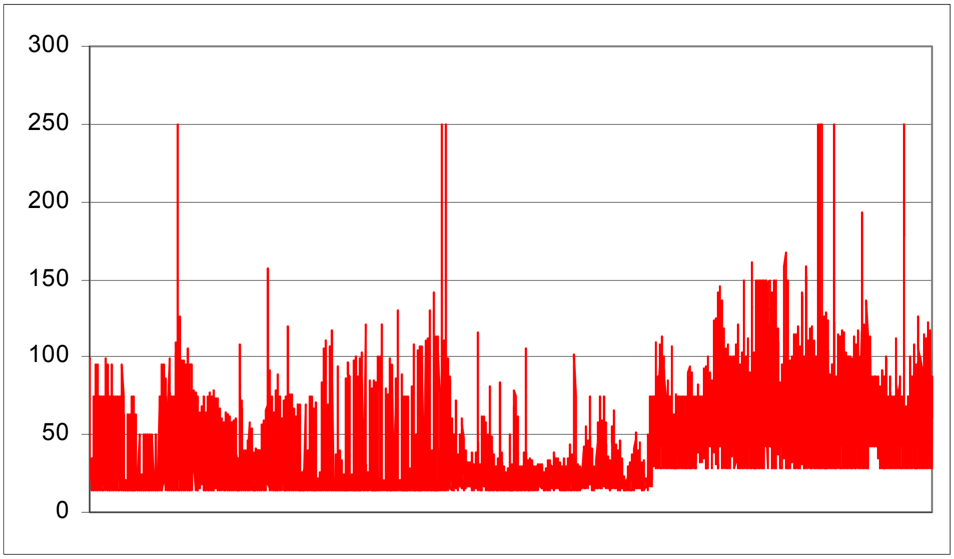


Figure Q.1. 2005 NYISO Regulation Service Clearing Prices

Table Q.2. 2005 NYISO Regulation Service Clearing Prices

	$/MWh
Minimum	14.00
Maximum	250.00
Mean	39.17
Median	28.00

5. Results

Note: Operating costs are $/MW per hour of regulation service, not $/MWh.

Table Q.3. Regulation Benefit, Net of Total Operating Cost, 2005

Operating Cost ($/MW per hour of regulation service)	Benefit ($/kW-yr)
0	343
50	181
100	40
150	8
200	4

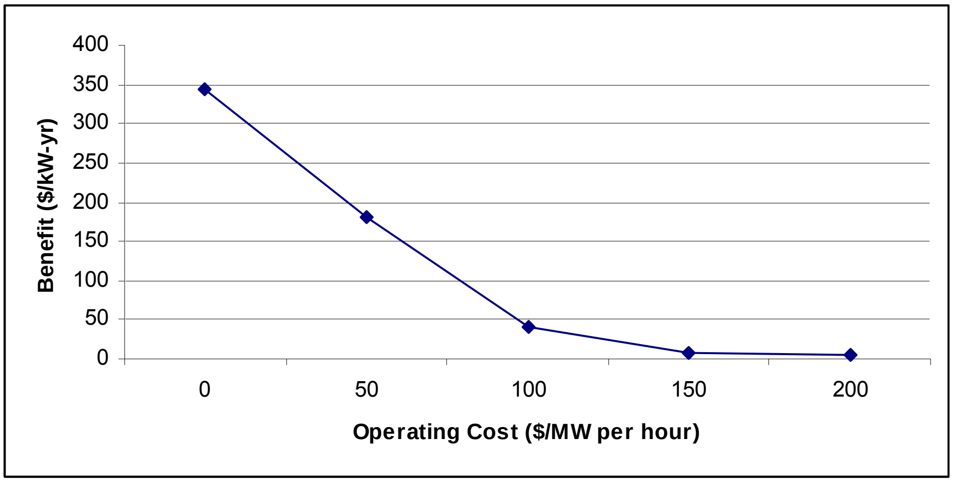


Figure Q.2. Regulation Benefit, Net of Total Operating Cost, 2005

Appendix R. Rapid Response Storage for Utility Applications

This appendix provides background regarding two possible applications for rapid response energy storage. That is, storage whose power output can vary swing from a full charging mode to a full discharge mode in seconds.

The primary reference for this document is the EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications which is available online at http://www.epri.com/OrderableitemDesc.asp?product_id=000000000001001834

Two Notable Applications for Rapid Response Storage

The following two sections are excerpts from the EPRI-DOE Storage Handbook.

Frequency Excursion Suppression

> Energy storage systems equipped with fast-acting grid interface power electronics offer an alternative to the traditional strategy of maintaining adequate spinning reserve margin to mitigate frequency contingencies. In response to such events, energy storage systems can supply "prompt" spinning reserve (PSR), i.e., rated power deployed within a few cycles for a sufficient period to enable other generation assets (e.g., Replacement Reserves) to be brought on line. The PSR approach avoids the capital and operating costs associated with continuously operating spinning reserve generation at part load and can be designed to provide regulation, voltage control and black start capability within the same facility. As the energy storage industry matures, it is likely that PSR will be considered within the energy market as an "ancillary service." [3]

Voltage Stability using Real Power

> Although the introduction of real power is theoretically unnecessary to establish voltage stability, analyses indicate that a small amount of real power significantly improves system performance by increasing the rate at which stability is restored and/or by decreasing the rating required of the power conditioning system, as well as the amount of reactive power needed.
>
> Such relationships are illustrated in Figure 3-4 [of the report, not shown here] which shows the results of analyses of Wisconsin Power System's (WPS) Northern Loop where 115kV line outages caused low voltages and fast voltage collapse on the system. As indicated in the figure, the options evaluated are static VAR Compensators (SVC), distributed STATCOMs and distributed STATCOMs with additional energy storage. [1] [2] [4]

References

[1] D-SMES Applications for Transmission and Power Quality Improvement, Bud Kehrli, EPRI Working Group Meeting, February 26, 2002.

[2] The Advent of Energy Storage for Transmission Voltage Stability Support via UltraCapacitors (TUCAP) and the Emitter-Turn-Off (ETO) Thyristor as an Advanced Power Electronic System, Consortium for Advanced Power Electronics and Storage, Dale Bradshaw, Tennessee Valley Authority, November 14-15, 2002.

[3] Mears, L. Gotschall, H. EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications. Report # 1001834. December, 2003. Pages 3-6. Available at http://www.epri.com/OrderableitemDesc.asp?product_id=000000000001001834

[4] Ibid. Page 3-8.

Appendix S. Reduce Time-of-Use Tariffs and Energy Cost

This appendix includes details of the evaluation of end-user bill reduction for time-of-use energy pricing.

Time-of Use Energy Tariffs

Demand Charges

Table S.1. shows details about the two relevant rates within the PSC No. 9 Tariff, Customer Class 9. Rate II applies to end users with larger loads (greater than 1,500 MW in most cases, greater than 900 MW in special cases) and Rate III applies to smaller loads that opt for time-of-use pricing. Demand charges are similar in magnitude for the two rates, approximately $180/kW of peak demand.

Energy Charges

The current version of Rider M in Con Edison tariffs – which took effect on May 1, 2006 – describes implementation of Mandatory Hourly Pricing (MHP) for the electric energy commodity. Rider M applies to end users whose peak demand exceeds 1,500 kW, and 2) end-users served under terms of tariff Riders I, J or L and with 900 kW of peak demand. The commodity-related charge in tariffs is referred to as the Market Supply Charge (MSC).

The MSC reflects zonal wholesale energy prices, adjusted for losses, plus several other relatively modest charges. One such charge is for ancillary services. As of May 11, 2006 the Rider M customers taking service under Con Edison's PSC No. 9 tariff will pay $0.4478 per kWh for ancillary services.

In effect, terms of Rider M provide a *default* way for end-users with large demand to purchase electric energy. The alternative – that is used by most end-users with large demand – is a relationship with an energy service company (ESCO) that provides the energy.

As of May 2006, Rider M is available at the following web address:
http://www.coned.com/documents/

Rates, including the PSC No.9, Customer Class 9 rates, are provided at
http://www.coned.com/rates/

Table S.1. Demand and Energy Delivery Charges, PS 9 Tariff, Customer Class 9, Rates II and III

Rate II - General - Large - Time-of-Day

Applicability: To Customers not subject to Rate II that elect to be billed at a time-of-day rate.

Demand Charge (per kilowatt of maximum demand for each time period)

Month	Time Period	Demand Charge
June, July, August, September	Mon.-Fri., 8 AM - 6 PM	$5.47
	Mon.-Fri., 8 AM - 10 PM	$10.24
	All hours - all days	$10.11
All other months	Mon. - Fri., 8 AM - 10 PM	$7.55
	All hours - all days	$3.27

Energy Delivery Charge (cents per kilowatthour)

Month	Time Period	Energy Delivery Charge
All months	All hours - all days	0.52

Rate III - General - Large - Voluntary Time-of-Day

Applicability: To Customers not subject to Rate II and that elect to be billed at a time-of-day rate.

Demand Charge (per kilowatt of maximum demand for each time period)

Month	Time Period	Demand Charge
June, July, August, September	Mon.-Fri., 8 AM - 6 PM	$4.73
	Mon.-Fri., 8 AM - 10 PM	$10.26
	All hours - all days	$9.79
All other months	Mon. - Fri., 8 AM - 10 PM	$6.56
	All hours - all days	$2.73

Energy Delivery Charge (cents per kilowatthour)

Month	Time Period	Energy Delivery Charge
All months	All hours - all days	0.52

Primary Reference

Case 03-E-0641, Mandatory Hourly Pricing for Commodity Service. April 27, 2006. Revisions to Consolidated Edison’s Schedule for Electric Service, P.S.C. No. 9. - Electricity and Retail Access Rate Schedule, P.S.C. No. 2. – Retail Access.

Non-energy Variable Charges

Table S.2. shows values for the two key charges not related to energy that apply under Rider M: Ancillary Services and NYPA Transmission Adjustment Charges (NTAC).

Table S.2. Rider M Ancillary Services and NTAC Charges

Summary of "Ancillary Service Charges" and "NYPA Transmission Adjustment Charges (NTAC)" Per kWh Charges Applicable to Bills Rendered Monthly to Customers who are Served under Rider M of PSC No. 9

Year: 2006

effective date	*Ancillary Service Charges (in cents/kWh)*		*NYPA Transmission Adjustment Charges (NTAC) (in cents/kWh)*	
	New York City Zone *	Westchester Zone **	New York City Zone *	Westchester Zone **
4/13/2006	0.3653	0.3653	0.0475	0.0475
5/11/2006	0.4478	0.4478	0.0593	0.0593

Evaluation Worksheet

The following is the worksheet used to evaluate prospects for storage used to reduce electricity bills for end users time-of-use energy charges.

Please see Appendix D for a breakdown of zonal, seasonal, and time-of-day energy prices.

Summer Demand and Energy Demand

Peak Load (kW) 1,000
Maximum Demand (kW) 920
Days/Year -- Summer 85

Storage Power (kW) 80
Storage Discharge Duration (hours) 4.9

Summer Daily Energy Cost
No Storage 2,057
With Storage 2,031

Energy Cost Reduction
($/day) 25.7
($/year) 2,184
($/kW-year) 27.3

Winter Energy

Days/Year -- Winter 176
Energy Price, Average ($/kWh)
Off-Peak 0.06
On-Peak 0.1

Winter Storage Energy benefit
Charging Cost ($/kW-year) 64
Discharge Value ($/kW-year) 86
Net ($/kW-year) 21

Storage

Storage Efficiency 80%

Storage Charge Duration (hours) 6.1
Storage Charging Time (hours) 6.1 0.01 ok

Energy Cost Reduction
Summer ($/kW-year) 27.3
Winter ($/kW-year) 21
Total 49

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Hourly Price ($kWh)	0.075	0.075	0.075	0.09	0.1	0.12	0.13	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.17	0.17	0.16	0.14	0.12	0.1	0.095	0.09	0.09	0.08
Load Factor	0.2	0.2	0.2	0.3	0.38	0.44	0.47	0.52	0.6	0.85	0.91	0.97	0.98	0.99	1	1	0.97	0.92	0.72	0.61	0.5	0.45	0.3	0.25
Charge Factor	1	1	1	1	0.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
Hourly Load	200	200	200	300	380	440	471	523	600	850	910	970	980	990	1000	1000	970	920	720	610	500	450	300	250
Energy Cost	15	15	15	27	38	52.8	61.2	73.3	90	128	146	155	167	168	170	170	155	129	86.4	61	47.5	40.5	27	20
Maximum Demand	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920	920
Load Reduction	0	0	0	0	0	0	0	0	0	0	0	50	60	70	80	80	50	0	0	0	0	0	0	0
Modified Load	280	280	280	380	388	440	471	523	600	850	910	920	920	920	920	920	920	920	720	610	500	450	380	330
Energy Cost Modified	21	21	21	34.2	38.8	52.8	61.2	73.3	90	128	146	147	156	156	156	156	147	129	86.4	61	47.5	40.5	34.2	26.4

Acronyms and Definitions

Acronyms

ACE – Area Control Error
AGC – automatic generation control
ATC – Available Transfer Capability
AVR – Active Voltage Regulators
BME – Balancing Market Evaluation
BPCG – Bid Production Cost Guarantee
CAES – Compressed Air Energy Storage
CHP – Combined Heat and Power
CCHP – Combined Cooling, Heating and Power
ConEd – Consolidated Edison
CPS – Control Performance Standard
DAM – Day-ahead Market
DCS – Disturbance Control Standard
DER – Distributed Energy or Distributed Energy Resources
DES – Distributed Energy or Distributed Energy Resources
DG – Distributed Generation
DM – Demand Management
DR – Demand Response
EE – Energy Efficiency
EPRI – Electric Power Research Institute.
ESCOs – Energy Service Companies
FERC – Federal Energy Regulatory Commission
FPA – Federal Power Act
ICAP – Installed (Electric Supply) Capacity
IPP – Independent Power Producer
ISO – Independent System Operator
kW – KiloWatt of power
LMP – Locational Marginal Price
LBMP – Locational Based Marginal Price
LIPA – Long Island Power Authority
LOLE – Loss of Load Expectation
LOLP – Loss of Load Probability
LSE – Load Serving Entity
MES – Modular Energy Storage
MHP – Mandatory Hourly Pricing
MSC – Market Supply Charge
MW – MegaWatt of power
MWh – MegaWatt-hour of energy
NERC – North American Electric Reliability Council
NITS – Network Integration Transmission Service
NPCC – Northeast Power Coordinating Council
NYC – New York City

NYCA – New York Control Area
NYS – New York State
NYSERDA – New York State Energy Research and Development Authority
NYISO – New York Independent System Operator
NYSBPS – New York State Bulk Power System
NYSRC – New York State Reliability Council
OASIS – Open Access Same-time Information System
OATT – Open Access Transmission Tariff
ORNL – Oak Ridge National Laboratory
PF – Power Factor
POI – Point of Injection
POW – Point of Withdrawal
PQ – Power Quality
PSC – Public Service Commission (The New York Department of Public Service)
PSR – Preliminary Status Report
RPS – Renewable Portfolio Standards
RR – Retail Rate
RT-AMP – Real-Time Automated Mitigation Process
RTC – Real-Time Commitment
RTD – Real-time-Dispatch
RTD-CAM – Real-Time Dispatching–Corrective Action Mode
RTO – Regional Transmission Organization
RTS – Real Time Scheduling
RTSC – Retail Transmission Service Charge
SBC – System Benefits Charge
SCR – Special Case Resource
SCUC – Security Constrained Unit Commitment
SMD – Standard Market Design
SMD2 – Standard Market Design 2 (implemented February 1, 2006).
TCC – Transmission Congestion Contract
TO – Transmission Organization
TTC – Total Transfer Capability
TSA – Thunder Storm Alert
TSC – Transmission Service Charge
TUC – Transmission Usage Charge
TWA –Transmission Wheeling Agreement
UCAP – “Unforced” Capacity -- effective fleet capacity, after forced outages
VAR – Volt Amp Reactive (also kVAR and MVAR)
VA – Volt Amp (also kVA and MVA)
VOC – Variable Operating Cost

Definitions

Apparent Power – The product of the root-mean-square (rms) voltage and the rms current in an AC circuit. When the impedance of current flow in a circuit is due entirely to resistance, the apparent power is the same as the true power. But the presence of reactance -- due to capacitance and/or inductance in circuits -- reduces delivery of usable (true) power (so the apparent power is greater than the true power).

Application – A specific way or ways that energy storage is used, to satisfy a specific need; how/for what energy storage is used.

Benefit – See Financial Benefit.

Beneficiaries – Entities to whom financial benefits accrue due to use of a storage system**.**

Bid Production Cost Guarantee (BPCG) – The mechanism used by the NYISO to ensure that qualifying generation facilities that commit power plants (i.e., started up or "turn on") will not operate at a financial loss. Elements are: a) Energy Bid, b) Minimum Generation cost, and c) start-up cost less d) net Ancillary Services Margin. BPCG is paid to suppliers daily.

Energy Price Buy Low – Sell High (a.k.a. Energy Price Arbitrage) – Purchase of inexpensive electricity during off-peak periods when demand for electricity is low, to charge the storage plant so that the low priced energy can be used or sold at a later time when demand/price for electricity is high.

C&I – Commercial and Industrial energy end-users.

Carrying Charges – The annual financial requirements needed to service debt or equity capital used to purchase and to install the storage plant, including tax effects. For utilities, this is the revenue requirement. See also: *Fixed Charge Rate*.

Combined Applications – Energy storage used for two or more <u>compatible</u> applications.

Combined Benefits – Sum of all benefits that accrue due to use of an energy storage system, irrespective of the purpose for installing the system.

Design Rating – The amount of power needed for a given situation, including engineering contingency (oversizing) to address uncertainty.

Discharge Duration – Total amount of time that the storage plant can discharge, at its nameplate rating, without recharging. Nameplate rating is the nominal full load rating, not “emergency,” “short duration,” or “contingency” rating.

Delivery Factor – Defined for a source of power, it equals the amount of power that could be delivered to a load at the reference bus if generation at the source is increased by 1 MW. When losses decrease, as a result of this specific power transfer, the delivery factor is greater than 1.0. When losses increase, as a result, the delivery factor is less than 1.0.

Discharge Duration – The amount of time that a storage system can discharge, at its rated power output, when fully charged.

Discount Rate – The interest rate used to discount future cash flows to account for the time value of money. For this document the standard assumption value is 10%.

Economic Benefit – The sum of all financial benefits that accrue to all beneficiaries using storage. For example, if the average financial benefit is $100 for 1 million storage users then the economic benefit is $100 * 1 million = $100 Million of economic benefit. See Financial Benefit.

Efficiency (**Storage Efficiency**) – See Round Trip Efficiency.

Emergency Rating – The amount of power that device/system can deliver on an “emergency” basis, for short periods of time, without significant equipment damage. See also Nominal Rating.

Energy Technologies – Energy storage systems that are best suited to store relatively significant amounts of energy for discharge durations of many minutes to hours or even days. See also Power Technology.

Export – Transmitting power to loads that are outside of New York.

Financial Benefit (Benefit) – Monies received and/or cost avoided by a specific beneficiary, due to use of energy storage.

Financial Life – is the plant life assumed when estimating lifecycle costs and benefits. A plant life of 10 years is assumed for lifecycle financial evaluations in this document (i.e. 10 years is the standard assumption value).

Fixed Charge Rate – The Fixed Charge Rate is used to convert capital plant installed cost into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes. The standard assumption value for Fixed Charge Rate is 0.13 for utilities.

Installed Capacity (ICAP) – Nameplate rating of generation “installed capacity” of the generation fleet. See also Unforced Capacity (UCAP).

Lifecycle – See Financial Life.

Lifecycle Benefit – Present worth of financial benefits that are expected to accrue over 10 years for a storage plant.

Locational Marginal Price (LMP) – The price for electricity or related services at a specified location or “node.”

Locational Based Marginal Price (LBMP) – The official term used in New York for locational marginal price.

Market Estimate – The estimated amount of energy storage capacity (MW) that will be installed. For this document, market estimates are made for a ten year period. Market estimates reflect consideration of prospects for lower cost alternatives to compete for the same applications and benefits. (For context, the Market Estimate is a portion of the Maximum Market Potential.)

Maximum Market Potential – The maximum potential for actual sale and installation of energy storage, estimated based on reasonable assumptions about technology and market readiness and trends, and about the persistence of existing institutional challenges. In the context of this document, it is the plausible market potential, for a given application. (For context, the Maximum Market Potential is a portion of the Market Technical Potential.)

Market Technical Potential – The estimated maximum possible amount of energy storage (MW and MWh) that could be installed over 10 years, given purely technical constraints.

Nominal Rating – The rating – power or energy – for a system under normal operating conditions. See also Emergency Rating.

Open Access Transmission Tariff (OATT) – The tariff “non-discriminatory” (or open access) program in New York available to entities that need to use or share the transmission system in New York.

Plant Rating (Rating) – Storage plant ratings include two primary criteria: 1) Power: nominal power output and 2) Energy: the maximum amount of energy that the system can deliver to the load without being recharged.

Point of Injection (POI) – The point within the T&D system where electricity is injected.

Point of Withdrawal (POW) – The point within the T&D system where electricity is extracted.

Power Rating – Storage power rating is the *rate* at which a storage system delivers energy. Common units of electric power are Watts, kiloWatts (kW) and megaWatts (MW).

Power Technologies – Energy storage systems that are best suited to provide large amounts of power for short durations (i.e. they deliver small amounts of energy per event). See also Energy Technology.

Present Worth Factor (PW Factor) – A number used to convert an annual financial payment into the present worth for a series of such equal payments. A PW factor is a function of a specific combination of: a) investment duration (life), b) financial escalation rate (e.g., inflation), and c) discount rate. The standard assumption value for this criterion is based on a ten year life, 2.5% inflation, and 10% discount rate. The corresponding PW factor is 7.17.

Price Inflation Rate (Inflation) – The annual average rate at which the price of goods and services increases during a specific time period. For this document, inflation is assumed to be 2.5% per year.

Reactive Power – In alternating current circuits and loads, energy is stored in elements with inductance and capacitance. Reactive power is a measure of the stored energy that returns to the source during each alternating current cycle. It is the portion of total power flow that is attributable to stored energy (in the circuit or loads), which returns to the source. It is also described mathematically as the vector difference between the apparent and true power.

Real Power – In alternating current circuits, the portion of power flow that, averaged over a complete cycle of the AC waveform, results in net transfer of energy in one direction.

Reference Bus – One bus within the transmission system designated as the common reference point for establishing price at all specific locations, for energy losses and congestion.

Revenue Requirement – For a utility, the amount of annual revenue required to pay carrying charges for capital equipment and to cover expenses including fuel and maintenance. See also: Carrying Charges and Fixed Charge Rate.

Round Trip Efficiency – The amount of electric energy output from a given storage plant/system per unit of electric energy input.

Standard Assumption Values (Standard Values) – Standardized/generic values used for example calculations. For example, financial benefits are calculated based on the following standard assumption values: a 10 year lifecycle, 10% discount rate, and 2.5% annual inflation. See also: Standard Calculations.

Standard Calculations – Methodologies for calculating benefits and market potential – used in conjunction with Standard Assumption Values.

Storage Discharge Duration – See Discharge Duration.

Storage System Life (System Life) – The period during which the storage system is expected to be operated. For this document, the Storage System Life is equal to the Financial Life.

Transmission Usage Charge (TUC) – A market-based transmission charge which includes the congestion and marginal loss components of LBMPs.

Transmission Service Charge (TSC) – Charges for use of the transmission system that includes recovery of embedded cost of the transmission system. Charges are specific to a Transmission District.

Transmission Wheeling Agreements (TWAs) – TWAs govern the use of specific or designated transmission facilities that are owned, controlled, or operated by an entity for the transmission of energy in interstate commerce.

True Power – The portion of apparent power that is actually delivered to the load in an AC circuit. That portion depends on the amount of reactance and harmonics present.

Unforced Capacity (UCAP) – Portion of ICAP that is actually available, given resources' composite forced outage rate. Used for pricing of ICAP that is bought and sold. A rolling 12 month average of monthly forced outage rate is used to determine the amount of ICAP that can be sold in units of UCAP.

Uplift, Uplift Charges – The increased cost of generation beyond what has been scheduled by Security Constrained Unit Commitment (SCUC) analysis and a balancing market evaluation (BME). Common sources of uplift include: 1) dispatch of uneconomic units, needed for system stability or security, usually in the NYC area, 2) capacity that is scheduled but not used, 3) part load operation of scheduled generating units and resulting Bid Production Cost Guarantee (BPCG).

Variable Operating Cost – depending on the type of equipment; the variable cost associated with producing or delivering energy, not related to energy. For storage this is the variable cost incurred for each kWh delivered to load and is primarily related to wear and tear on storage vessels and chemicals leading to the need for periodic replacement or refurbishment.

Wheel Through – Transmitting electricity produced outside of a given area, through the respective area, to a third area (See *Transmission Wheeling Agreements*).

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Final Report 07-06; Volume II: Appendices

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