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Economics of
Emerging Electric Energy Storage Technologies
and Demand Response
in Deregulated Electricity Markets

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ABSTRACT

Unlike markets for storable commodities, electricity markets depend on the real-time balance of supply and demand. Although much of the present-day grid operates effectively without storage, cost-effective ways of storing electrical energy can help make the grid more efficient and reliable. I have investigated the economics of two emerging electric energy storage (EES) technologies: sodium sulfur (NaS) batteries and flywheels in the electricity markets operated by the New York Independent System Operator (NYISO) and the PJM Interconnection (PJM). The analysis indicates that there is a strong economic case for flywheel installations in both the PJM and NYISO markets for providing regulation services. The economic case for NaS batteries for energy arbitrage is weak in both NYISO and PJM. Some of the uncertainties regarding regulation market rules are one of the reasons for lack of investment in flywheels. On the other hand, some market participants have already made investments in NaS batteries due to anticipated system upgrade deferral benefits. Capital cost reduction and efficiency are important factors that will influence the economics of NaS batteries for energy arbitrage in deregulated electricity markets.

I have also analyzed the economic demand response program offered by PJM. PJM's program provided subsidies to customers who reduced load in response to price signals before 2008. The program incorporated a "trigger point", set at a locational marginal price of $75/MWh, at or beyond which payments for load reduction included a subsidy payment. Particularly during peak hours, such a program saves money for the system, but the subsidies involved may introduce distortions into the market. I have simulated demand-side bidding into the PJM market, and compare the economic welfare gains with the subsidies paid to price-responsive load using load and price data for year 2006. The largest economic effect is wealth transfers from generators to non price-responsive loads. Based on the incentive payment structure that was in effect through the end of 2007, I estimate that the social welfare gains exceeded the subsidies during 2006. Lowering the trigger point increases the transfer from generators to consumers, but may result in the subsidy outweighing the social welfare gains due to load curtailment.

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1-1. Introduction

Although the present-day electric grid operates effectively without storage, cost-effective ways of storing electrical energy can help make the grid more efficient and reliable. Electric energy storage (EES) can be used to accumulate excess electricity generated at off-peak hours and discharge it at peak hours. This application could yield several benefits - a reduced need for peak generation (particularly from expensive peaking plants) and reduced strain on transmission and distribution networks. EES can also provide critically important ancillary services such as grid frequency regulation, voltage support, and operating reserves, thereby enhancing grid stability and reliability.

The term “EES” as used in this dissertation refers specifically to the capability of storing energy that has already been generated as electricity and controllably releasing it for use at another time (EPRI, 2003). Although it is difficult to store electricity directly, electric energy can be stored in other forms, such as potential, chemical, or kinetic energy. Advanced EES technologies based on these principles are emerging as a potential resource in supporting an efficient electricity market. In general, large-scale applications of EES have been limited in the utility industry. Utility-scale EES projects based on storage technologies other than pumped hydro have been built, though they have not become common. Existing facilities include one compressed air energy storage (CAES) system, several plants based on lead-acid batteries, and one based on nickel-cadmium batteries. In all, roughly 2.5% of the total electric power delivered in the United States passes through energy storage, largely pumped hydroelectric. The percentages are somewhat larger in Europe and Japan, at 10% and 15%, respectively (EPRI, 2003).

The restructuring of the electricity industry, along with increased requirements for power reliability and quality has made utility-scale EES more attractive. This has stimulated research and development of a number of new EES technologies. Representative technologies include redox flow batteries (Bartolozzi, 1989; Price, 2000), sodium-sulfur batteries (Oshima et al., 2005), lead-acid batteries (EPRI, 2003), flywheels (Lazarewicz, 2005), pumped hydroelectric storage (Perekhodtsev, 2004), and compressed air energy storage (CAES) (DeCarolis and Keith, 2006). Battery and flywheel technologies are geographically less constrained than hydroelectric storage or CAES.

1-2. Review of emerging EES technologies

EES technologies can be grouped as electrochemical and non-electrochemical EES technologies. The most common EES technologies are listed below:

- **Electrochemical EES**
  - Lead Acid Battery
  - Sodium-Sulfur battery (NaS)
  - Flow Batteries
    - Vanadium Redox Battery (VRB)
    - Zinc Bromine Battery (ZnBr)
  - Nickel Cadmium (NiCd) Battery
  - Nickel Metal Hydride (NiMh) Battery
  - Lithium Ion (Li-ion) Battery
- **Non-Electrochemical EES**
  - Pumped Hydro

- Compressed Air Energy Storage (CAES)
- Flywheel
- Ultra-Capacitor
- Superconducting Magnetic Energy Storage (SMES)

The EES technologies listed above are described in detail in EPRI (2003, 2004) and Gyuk et al. (2005). Although all of these technologies are viable for utility-scale systems, some are believed to have more potential than others, as discussed below. Appendix 1-A provides a summary comparison of various EES technologies.

This research has evaluated the economics of two emerging EES technologies, sodium sulfur (NaS) batteries for energy arbitrage and flywheel EES systems for regulation services. I considered several factors in selecting technologies for market analysis. First, very large-scale storage such as pumped hydro and CAES continue to have potential where geographic considerations and other factors such as public acceptance allow their use. In New York state, most suitable pumped hydro sites have already been developed. Most prospective CAES sites are in western New York, where the economic case for energy storage is the weakest (Walawalkar et al. 2005), as discussed in Chapter 2. Second, lead-acid batteries were not included in this analysis because utilities are reluctant to accept this technology for electric market applications due to their relatively short service life, significant environmental effects, and high maintenance costs (EPRI 2003). Flow batteries such as Zinc bromine and Vanadium Redox batteries are less economically attractive than NaS batteries due to higher capital cost. With the currently available data, NaS batteries have the best economics among the advanced battery technologies for MW-size utility applications (EPRI, 2006). Third, the extremely high cycle life of flywheel devices make them viable solutions for applications such as frequency regulation. Ultra-capacitors and superconducting magnetic energy storage (SMES) devices, which also have excellent cycle life, may have potential in these applications, but are not yet mature enough to consider in a utility application.

The following section provides an overview of NaS batteries and flywheels considered in this research:

1-2-1. Sodium-Sulfur Batteries

Sodium-sulfur batteries are based on a high-temperature electrochemical reaction between sodium and sulfur, separated by a beta alumina ceramic electrolyte. While originally developed for electric vehicle applications, they were adapted for the utility market by the Tokyo Electric Power Company (TEPCO) and NGK Insulators, Ltd., both based in Japan. By the late 1990s, NGK and TEPCO had deployed a series of large-scale demonstration systems, including two 6 MW, 48 MWh installations at TEPCO substations. Sodium-sulfur batteries have excellent cycle life and are relatively mature products, with over 55 installations worldwide (EPRI, 2003).

In 2002, TEPCO and NGK announced full commercialization of their sodium-sulfur battery line under the trade name NAS®, for power quality and load shifting applications. Also in 2002, the first NaS battery was installed in the U.S. at an American Electric Power (AEP) laboratory at Gahanna, Ohio.

In 2005, the New York Power Authority (NYPA), with co-funding from Consolidated Edison, NYSERDA, the U.S. DOE, and other parties, sponsored the installation of a NaS battery rated at 1.2 MW and 7.2 MWh, for peak demand reduction and backup power at a Long Island Bus Company refueling station. AEP also installed a NaS battery at a substation near Charleston, West Virginia. This unit, also rated at 1.2 MW and 7.2 MWh, is designed to defer upgrades to the substation for six to seven years, allowing a significant reduction in capital expense. (Nourai, 2006) Both installations were completed in 2006. AEP is currently working on projects to add 6 MW of additional NaS batteries by 2008. AEP has set a goal of having 1,000 MW of advanced storage capacity on its system in the next decade (AEP, 2007).

Figure 1-1: AEP's NaS Installation (Nourai, 2006)

1-2-2. Flywheel Energy Storage

Flywheels store energy in the angular momentum of a spinning mass. During charge, the flywheel is spun up by a motor with the input of electrical energy; during discharge, the same motor acts as a generator, producing electricity from the rotational energy of the flywheel. Most products are capable of several hundred thousand full charge-discharge cycles and enjoy much better cycle life than batteries. They are capable of very high cycle efficiencies of over 90% (Lazarewicz, 2005). Since the energy sizing of a flywheel system is dependent on the size and speed of the rotor, and the power rating is dependent on the motor-generator, power and energy can be sized independently. The downside to flywheels comes from their relatively poor energy density and large standby losses. Beacon Power Corporation is currently testing flywheels for frequency regulation applications at the transmission level in New York and California (Gyuk et al., 2005; Lazarewicz, 2005). The Beacon Power flywheels are constructed of carbon and fiber glass composites to withstand up to 22,500 revolutions/min. The flywheel is housed in a vacuum sealed steel container and employs a high speed magnetic lift system to minimize friction. Flywheels are designed to shut down benignly in case of failure, and the composite material is designed to disintegrate in case of failure to avoid potential injuries. Beacon Power has also proposed that the flywheels can be installed underground to avoid any potential concern about safety. (Lazarewicz, 2005)

More recently, flywheels have been proposed for longer duration applications. Beacon Power Corporation has proposed a 20-MW flywheel energy storage system for frequency regulation applications at the transmission level. This application is being tested at a small scale in demonstrations in New York, funded by the New York State Energy Research and Development Authority (NYSERDA), and in California, funded by the California Energy Commission (CEC)[1].

Figure 1-2: Rahul Walawalkar with the Beacon Power flywheel test installation in California

[1] Source: http://www.sandia.gov/ess/About/projects.html

Table 1-1: Summary of the technical and cost details for two EES technologies

	NaS	Flywheel
EES Size	1 MW (10 MWh)	1 MW (0.25 MWh)
Total Capital Cost	$1,500,000 - 3,000,000	$750,000 -2,000,000
Annual O&M Cost	$15,000 - 90,000	$20,000 - $30,000
Cycle Life	5,000 - 20,000	100,000 - 2,000,000
Service Life (years)	12 - 20	15 - 25
Footprint (SqFt/MW)	900	150

Table 1-1 summarizes the EES technical parameters and costs for NaS batteries and flywheels. The base estimates were derived from the data available in EPRI (2003) and updated based on information from manufacturers and industry experts. The capital cost and annual operations and maintenance cost estimates have a relatively large range, as these technologies are yet to be widely commercialized, and no published data are available. For NaS batteries the cycle life (5,000 - 20,000 cycles) is sensitive to operational parameters such as depth of discharge and environmental factors, whereas for the flywheel the cycle life (100,000 - 2,000,000 cycles) is based on design specifications. The service life estimate was derived based on the cycle life and expected usage for various market applications.

1-3. Technical benefits of energy storage

Emerging EES systems (beyond traditional, but severely geographically limited, pumped hydroelectric storage) promise to provide several technical benefits for utilities, power system operations, and users. The traditional applications for energy storage are described below: (EPRI, 2003, EPRI, 2004, EPRI, 2006).

1-3-1. Grid Stabilization: EES can be used to help the transmission or distribution grid return to its normal operation after a disturbance. Energy storage can be used to remedy three forms of instability: rotor angle instability; voltage instability; and frequency excursions.

1-3-2. Grid Operational Support: In addition to stabilizing the grid after disturbances, energy storage can also be used to support normal operations of the grid. Four types of support operations can be performed through the use of energy storage:

- **Frequency Regulation Services:** Energy storage can be used to inject and absorb power to maintain grid frequency in the face of fluctuations in generation and load.

- **Contingency Reserves:** At the transmission level, contingency reserve includes spinning (or synchronous) and supplemental (non-synchronous) reserve units, which provide power for up to two hours in response to a sudden loss of generation or a transmission outage.

- **Voltage Support:** Voltage support involves the injection or absorption of reactive power (VARs) into the grid to maintain system voltage within the optimal range. Energy storage systems use power-conditioning electronics to convert the power output of the storage technology to the appropriate voltage and frequency for the grid.

- **Black Start:** Black start units provide the ability to start up from a shutdown condition without support from the grid, and then energize the grid to allow other units to start up. A properly sized energy storage system can provide black start capabilities, provided it is close enough to a generator.

1-3-3. Power Quality and Reliability: EES is often used to improve power quality and reliability. The vast majority of grid-related power quality events are voltage sags and interruptions with durations of less than 2 seconds, phenomena that lend themselves to energy storage-based solutions (EPRI 1998).

1-3-4. Load Shifting: Load shifting is achieved by utilizing EES for storage of energy during periods of low demand and releasing the stored energy during periods of high demand. Load shifting comes in several different forms; the most common is peak shaving. (EPRI 2003) Peak shaving describes the use of energy storage to reduce peak demand in an area. It is usually proposed when the peak demand for a system is much higher than the average load, and when the peak demand occurs relatively rarely. Peak shaving allows a utility to defer the investment required to upgrade the capacity of the network. The economic viability of energy storage for peak shaving depends on a number of factors, particularly the rate of load growth (EPRI 2003). The $/kW cost of a distribution upgrade is usually much lower than the $/kW cost of energy storage. But the total cost of a distribution upgrade is usually much higher than the total cost of an EES optimized for deferral of a distribution upgrade for two to five years. AEP has justified the installation of NaS battery in Charleston, WV, for peak shaving based on savings from deferring the upgrade of a substation (Nourai, 2006).

1-3-5. Supporting the integration of intermittent renewable energy sources: Wind power generation is presently the largest and fastest growing renewable power source. The following applications are described in the context of wind power (EPRI 2004). Similar applications also exist for renewable energy sources other than wind power, such as solar photo-voltaic (PV).

- **Frequency and synchronous spinning reserve support:** In grids with a significant share of wind generation, intermittency and variability in wind generation output due to sudden shifts in wind patterns can lead to significant imbalances between generation and load, which in turn result in shifts in grid frequency. Such imbalances are usually handled by spinning reserve at the transmission level, but energy storage can provide prompt response to such imbalances without the emissions related to most conventional solutions.

- **Transmission Curtailment Reduction:** Wind power generation is often located in remote areas which are poorly served by transmission and distribution systems. As a result, sometimes wind operators are asked to curtail their production, which results in lost energy production opportunity, or system operators are required to invest in expanding the transmission capability. An EES unit located close to the wind generation can allow the excess energy to be stored and then delivered at times when the transmission system is not congested.

- **Time Shifting:** Wind turbines are considered as non-dispatchable resources. EES can be used to store energy generated during periods of low demand and deliver it during periods of high demand. When applied to wind generation, this application is sometimes called “firming and shaping” because it changes the power profile of the wind to allow greater control over dispatch.

1-4. Information on recent U.S. initiatives

Currently, the U.S. Department of Energy (DOE) has two major initiatives to support development and integration of EES for electricity grid-related applications in association with the New York State Electric Research and Development Authority (NYSERDA) and the California Energy Commission (CEC). Details of these initiatives developed to demonstrate EES as a technically viable, cost-effective, and broadly applicable option for increasing the reliability and electric energy management of the electricity system are provided below:[2]

1-4-1. CEC/DOE Collaboration on Energy Storage: This collaboration is a partnership between the DOE Energy Storage Systems (ESS) Program and the CEC. In response to a CEC Program Opportunity Notice, three major projects totaling $9.6M were selected in 2005. DOE, through Sandia National Laboratories, oversees the technical management of these demonstration projects.

- A ZBB flow battery installed at a Pacific Gas & Electric substation to mitigate distribution congestion, provide voltage support, and reduce peak loads in the distribution system transformer. This demonstration project utilizes a zinc bromine battery storage system installed at an electric utility distribution substation. The objective is to defer a substation transformer upgrade until all associated planning and permitting can be accomplished.

- A Beacon Flywheel Energy Storage System (FESS) to demonstrate the feasibility of using a flywheel to provide frequency regulation services to the California Independent System Operator (CaISO). This project demonstrates a flywheel energy storage system designed to respond to a regional transmission operator signal to quickly add or subtract power from the grid in a frequency regulation support mode.

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[2] Source: http://www.sandia.gov/ess/About/projects.html

- A Dynamic Stabilizer using Maxwell ultra-capacitors to provide ride through for power interruptions to critical loads and mitigate power quality problems on a wind turbine/hydro micro grid for the Palmdale Water Treatment Plant. This project will demonstrate the use of an ultra-capacitor energy storage module in support of a selection of distributed energy resources that could potentially be configured as an electric microgrid. These resources include a 950 kilowatt wind turbine, a 200 kW natural gas generator, and a 250 kW water turbine generator.

1-4-2. NYSERDA / DOE Joint Energy Storage Initiative: This initiative is a partnership between the DOE ESS Program and the NYSERDA. In response to a NYSERDA Program Opportunity Notice, six projects totaling $5.6M were selected in 2004. They include three major demonstration projects that showcase flywheel, sodium-sulfur battery, and lead-acid battery technologies.

- The Residential Energy Storage and Propane Fuel Cell Demonstration project exhibits the use of an 11 kW, 20 kWh Gaia Power Technologies PowerTower energy storage system in conjunction with a Plug Power GenSys propane fuel cell in an edge-of-grid residential application. The demonstration consists of two parts:
    - Demand reduction using the PowerTower to provide an energy boost when the user load exceeds a preset threshold.
    - Demand reduction using the PlugPower propane fuel cell as a primary electricity source in conjunction with the PowerTower.

  Primary participants: Delaware County Electric Cooperative (utility), Gaia Power Technologies (equipment manufacturer), EnerNex Corporation (data acquisition and monitoring).

- The Flywheel-Based Frequency Regulation Demonstration project (FESS), located at an industrial site in Amsterdam, NY, demonstrates grid frequency regulation by utilizing a high-energy flywheel storage system that consists of seven Beacon Power flywheels which have been adapted to operate on the Niagara Mohawk distribution grid. This system is capable of providing 100 kW of power for frequency regulation and storing 25 kW of recoverable energy.

Primary participants: Beacon Power (equipment manufacturer), NationalGrid (utility), EnerNex Corporation (data acquisition and monitoring).

- The NaS Battery Demonstration project at a Long Island bus depot facility exhibits the use of a NaS battery system that shifts compressor peak load to off-peak capacity and provides emergency backup power. The primary application will be to supply up to 1.2 MW of power to a natural gas compressor for six to eight hours per day, seven days per week, especially during the summer peak period.

  Primary participants: ABB, Inc. (PCS Manufacturer), New York Power Authority (NYPA), NGK Insulators, Ltd. (battery manufacturer), EnerNex Corporation (data acquisition and monitoring).

1-5. Opportunities for EES integration in deregulated electricity markets

An EES unit can participate in electricity markets in a number of ways, depending on its energy storage and delivery characteristics (Schoenung et al. 1996). Despite numerous advances in EES technologies (Gyuk et al.,2005) and technical benefits offered (EPRI 2003), markets have not yet adopted EES applications other than pumped hydro on a large scale.

Initial economic studies of EES systems focused on applications for peak shaving and as capacity resources (Sobieski and Bhavaraju 1985). In recent years there has been increased attention to evaluating the economics of EES systems as backup for intermittent renewable sources. Some examples include wind and CAES (DeCarolis and Keith 2006), wind and hydro or batteries (Bathurst 2003), solar photovoltaic and batteries (Su et al. 2001; Fabjan et al. 2001).

Since the emergence of deregulated electric energy markets, several studies of the economics of EES systems have appeared, including a ranking of potential opportunities (Butler et al. 2003), life-cycle costs for batteries, CAES, and flywheels (Schoenung and Hassenzahl, 2003), a general calculation of potential revenues in California and PJM without regard to technologies (Eyer et al., 2004), pumped hydroelectric storage using PJM market data (Perekhodtsev, 2004) and comparison of energy arbitrage revenues (from storing power purchased at off-peak times and selling it on-peak) in North American and European energy markets (Figueiredo et al., 2005).

In addition to the traditional applications described in section 1-3, the restructuring of the electricity industry has created additional opportunities for integration of EES into the electric grid and has provided a means to quantify the benefits of some of the traditional applications. This research has evaluated the economics of EES in wholesale electricity markets operated by New York ISO (NYISO) and the PJM Interconnection (PJM). The NYISO and PJM markets were chosen for this analysis because market data are readily available and an initial survey indicated that both energy arbitrage and regulation services might be profitable there. Figure 1-3 shows the average daily price curves for energy and ancillary service markets in NYISO based on 2001-07 average prices for each hour of the day. Below I have listed various markets operated by NYISO and PJM that allow EES to participate:

1-5-1. Energy Market (Day Ahead and real time): This market provides a mechanism for market participants to buy and sell energy. EES can buy energy at an off-peak price and sell during on-peak hours directly into the market or can be party to a bilateral contract.

1-5-2. Ancillary Services Markets: These markets support the transmission of real power and reactive power from resources to loads and are used to maintain reliable operation of the power grid.

- **Regulation and frequency support:** for the continuous balancing of resources with load, in accordance with NERC criteria. This service is accomplished by committing online generators whose output is raised or lowered, usually in response to an

Automatic Generation Control (AGC) signal, as necessary to follow moment-by-moment changes in load.

- **Spinning (or Synchronized), Non-Spinning and Operating Reserves:** to provide backup generation in the case of a loss of major generating resources or transmission due to either to a power system contingency or equipment failure.

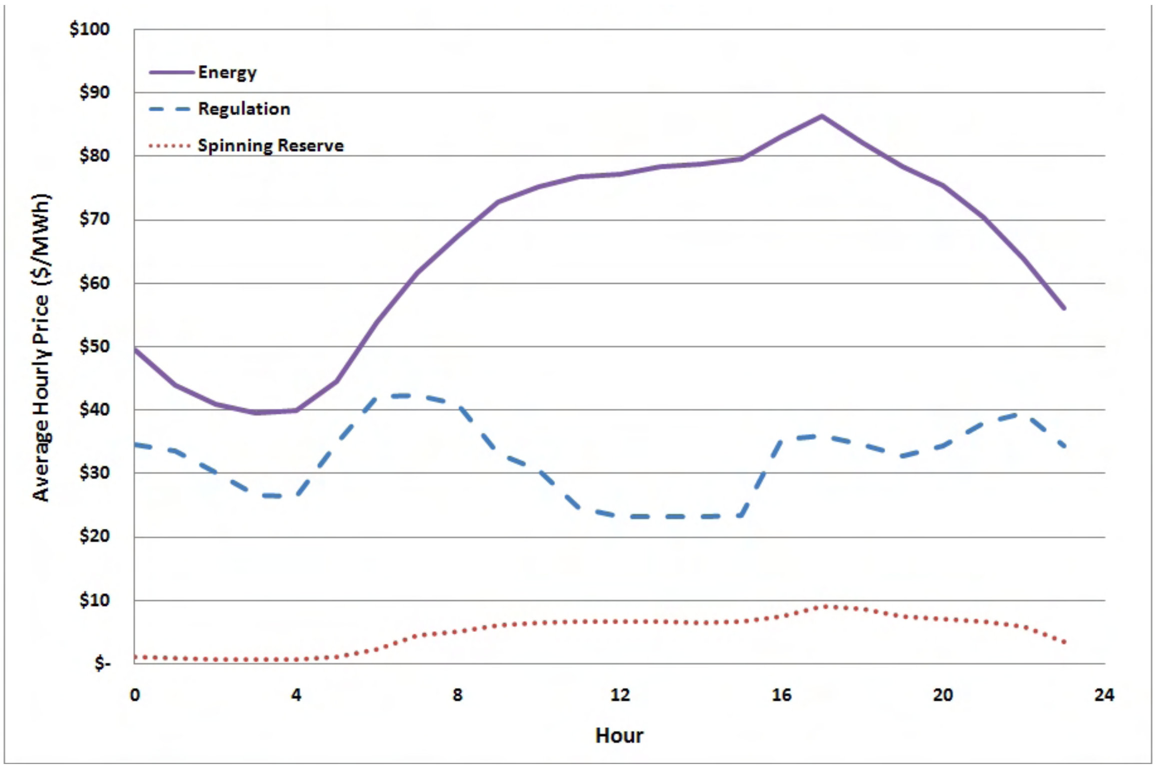

Figure 1-3: Average daily price curves for energy, regulation and spinning reserves in NYISO (2001-07) (Source: NYISO Market data)

1-5-3. Installed Capacity Market: This market has been established to ensure that there is sufficient generation capacity to cover the capacity requirements. EES systems that meet the reliability criteria specified by the system operator can earn the capacity revenue in addition to energy arbitrage and ancillary service revenue.

1-5-4. Demand Response programs: Both NYISO and PJM have developed emergency and economic demand response (DR) programs. Behind-the-meter (i.e. end use customer side of the utility meter) installations of EES technologies can be eligible to participate in demand response programs. Qualifying installations may also be eligible for capacity revenues under Special Case Resource (SCR) program in NYISO and Interruptible Load Resource (ILR) program in PJM.

Chapter 2 covers the economics of EES in the NYISO electricity market, and chapter 3 covers the economics of EES in the PJM electricity market. Chapter 4 discusses the economic demand response program in PJM in detail.

1-6. Demand response programs in deregulated electricity markets

Historically, electric utilities in North America have been authorized by their regulatory bodies to recoup their costs of generation, transmission, and distribution on an average-cost basis. In addition, utilities were generally allowed a regulated rate of return based on installed assets. Thus, utilities traditionally had been motivated to obtain more equipment and systems, within reason. Most customers are served under rates based on average embedded costs. Except for larger consumers who were billed for time of use (TOU), most consumers just paid the average price for the energy they consumed, regardless of when consumed. As a result, consumers have had little incentive to control their electricity consumption in response to system requirements. Independent System Operators (ISOs) such as NYISO, PJM, and ISO-New England have developed DR programs to help reliability and provide efficient operations in competitive electricity markets.

Fundamentally, DR programs require cooperation (either explicit or implicit) between the consumers and the service providers (utilities, ISOs, etc.). Demand Response programs are utilized by electric utilities and ISOs to encourage consumers to modify their electric demand. DR refers only to activities that modify energy and load shape undertaken in response to economic or reliability signals provided by utilities or ISOs and not to load-shape changes arising from normal operation. Based on the type of signal used to activate the DR program, these programs can be categorized as either emergency DR programs (reliability based) or economic DR programs (price based). Fig 1-3 shows the classification of various DR programs and the criteria for participation.

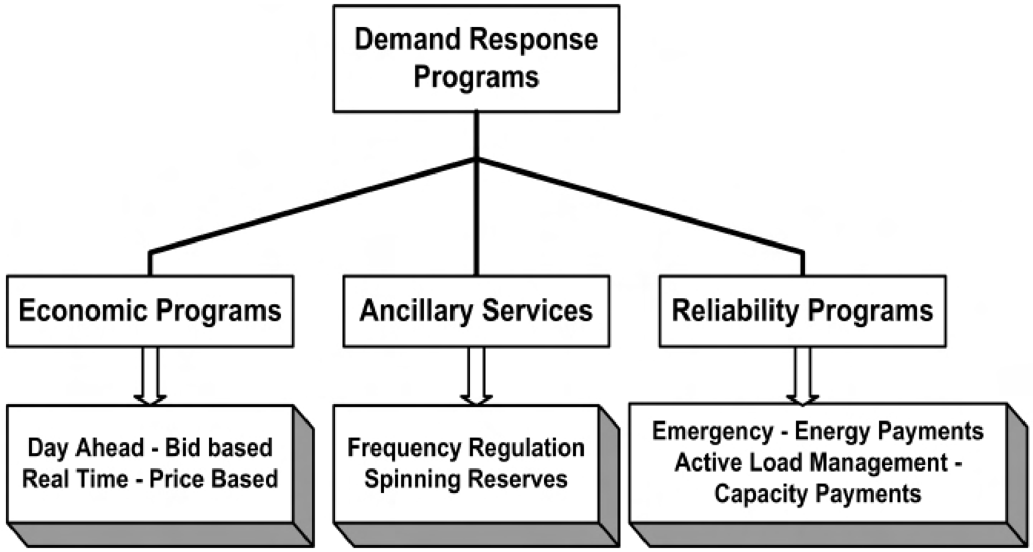

Figure 1-4: Classification of common demand response programs in the U.S.

(Walawalkar et. al., 2007)

The emergency DR programs aim to provide cost-effective capacity resources to help avoid system outages in cases of severe grid stress. On the other hand, economic DR programs are developed to exert a downward pressure on electricity prices by allowing demand-side participation in electricity markets through voluntary reductions during high priced usage hours. In recent years ISOs have started to explore ways to utilize DR resources also for providing ancillary services (frequency regulation or spinning reserves). PJM started allowing DR resources to participate in ancillary services markets in 2006. These programs can help defer the need for new sources of power, including generating facilities, power purchases, and additions to transmission and distribution capacity. All DR programs rely on end users deliberately altering their use of equipment and systems, which generally means lifestyle or comfort changes or changes in operating procedures. Such changes would be acceptable to end users only if the consumer has a stake in the process either through financial compensation or through improved reliability of the power supply.

In recent years, various research groups have tried to quantify the social benefits of DR in U.S. markets. A 2001 study by McKinsey & Company estimates that at the US level, $10-15 billion per year in benefits can be achieved from participation of all customers in DR programs on a wide scale, with the majority of the potential, contrary to conventional wisdom, from residential sector DR efforts (McKinsey 2001). Another study by the Rocky Mountain Institute suggests that lowering demand by 5% of the system's maximum can reduce peak wholesale power market prices by 90%, as utilities and independent system operators reduce their need to purchase on-peak power (RMI, 2002). Such a drop in wholesale peak prices also means that non-participants in demand response programs also share in the benefits, as prices for everyone are held in check. Based on a review of current utility programs, EPRI estimates that DR has the potential to reduce current U.S. peak demand by 45,000 MW (EPRI, 2001). FERC released a cost-benefit analysis that showed a $60 billion savings over the next 20 years if DR is incorporated into Regional Transmission Organization (RTO) market design and operations (FERC 2002).

While DR is not the answer to all the difficulties in electricity restructuring and wholesale market design, it is certainly one of the missing links. These new programs are considered an essential component for "competitive markets" being developed across the country by allowing interaction of supply and demand curves. Chapter 4 focuses on an economic welfare evaluation of the economic DR program offered by PJM. Section 4-2 covers the issues related to the subsidy payment, which was incorporated into the incentive payment in the original PJM economic DR program. Although PJM has integrated the economic DR program into the market design, the provision for the subsidy payment expired on December 31, 2007. We discuss whether this subsidy payment can be justified based on the net social welfare gain due to economic DR participation. Chapter 4 also deals with the effect of the removal of the subsidy on individual DR participants.

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Appendix 1-A. Summary of EES technologies (EPRI 2003, EPRI 2004, EPRI 2006, Schoenung 2003, Gyuk 2005, Price 2000)[3]

EES Technology	**Advantages**	**Disadvantages**	**Major Applications**	**Customer**	**Potential Improvements**
Lead Acid	❑ Mature technology - over a century old ❑ Familiar - the most widely used EES system on earth ❑ Inexpensive ($/kW) - $600 - $1600 ❑ Ready availability (45-50% of battery sales)	❑ Low specific energy (kWh/kg) and specific power (kW/kg) ❑ Short cycle life (100-1000) ❑ High maintenance requirements ❑ Environmental hazards (lead and sulfuric acid) ❑ Capacity falls with decreasing temperature below 77 degrees F	❑ Automobile ❑ UPS/Telecom/Substation reserve power	❑ Utilities (Generation, Transmission and Distribution) ❑ Residential, commercial, industrial customers ❑ Automobile end users	❑ Cycle Life ❑ Depth of Discharge (DOD) ❑ Performance at low ambient temperatures

[3] The author would like to acknowledge help and guidance from Mr. Haresh Kamath of EPRI and Mr. Rick Mancini of Customized Energy Solutions in developing this summary comparison.

EES Technology	**Advantages**	**Disadvantages**	**Major Applications**	**Customer**	**Potential Improvements**
Sodium Sulfur (NaS)	❑ High energy and power density ❑ Relatively high efficiency ❑ Long cycle life ❑ Relatively well-established	❑ Relatively expensive (still small volume manufacturing) ❑ High temperature produces unique safety issues	❑ Peak shaving for T&D upgrade deferral ❑ Small load leveling applications	❑ Utilities (Generation, Transmission and Distribution) ❑ Industrial customers	❑ Lower cost
Vanadium Redox Battery (VRB)	❑ Energy and power sizing is independent ❑ Scalable for large applications ❑ High energy and power density ❑ Easily upgradeable	❑ Relatively early-stage technology ❑ Relatively expensive ❑ Limited opportunities for standard sizes	❑ Peak shaving for &TD upgrade deferral ❑ Small load leveling applications ❑ Backup power applications	❑ Utilities (Generation, Transmission and Distribution) ❑ Industrial customers	❑ Lower costs ❑ Improved standardizatio n ❑ Safety protocols for special locations (i.e., urban areas)

EES Technology	Advantages	Disadvantages	Major Applications	Customer	Potential Improvements
Zinc Bromine Battery (ZBB)	❑ Energy and power sizing are partially independent ❑ Scalable for large applications ❑ High energy and power density	❑ Relatively early-stage technology ❑ Potentially high maintenance costs ❑ Safety hazard: corrosive and toxic materials require special handling	❑ Peak shaving for T&D upgrade deferral ❑ Small load leveling applications ❑ Backup power applications	❑ Utilities (Generation, Transmission and Distribution) ❑ Industrial customers	❑ Lower costs ❑ Improved control methodology ❑ Improved safety protocols
Li-ion (Cobalt Oxide-based)	❑ High energy and power density ❑ Higher efficiency	❑ High cost - limited availability of cobalt ❑ Requires sophisticated battery management ❑ Safety issues require special handling	❑ Consumer electronics ❑ Automobile (hybrid electric vehicles and plug-in hybrid electric vehicles) ❑ Utility applications are possible	❑ Utilities (generation, transmission and distribution) ❑ Automobile and consumer electronics end users	❑ Lower costs ❑ Improved safety methodologies ❑ Improved thermal management systems ❑ Improved battery management systems

EES Technology	Advantages	Disadvantages	Major Applications	Customer	Potential Improvements
Li-ion (Phosphate-based)	❑ High energy and power density (though not as high as $LiCoO_2$-based) ❑ Higher efficiency ❑ Lower cost than $LiCoO_2$-based technologies	❑ Relatively early-stage technology ❑ Requires sophisticated battery management ❑ Safety issues (though safer than $LiCoO_2$-based technologies)	❑ Consumer electronics ❑ Automobile (hybrid electric vehicles and plug-in hybrid electric vehicles) ❑ Utility applications are possible	❑ Utilities (generation, transmission and distribution) ❑ Automobile and consumer electronics end users	❑ Lower costs ❑ Improved safety methodologies ❑ Improved cycle life ❑ Improved thermal management systems ❑ Improved battery management systems
Ni-Cd	❑ Mature technology ❑ Relatively rugged ❑ Higher energy density and ❑ Better cycle life than lead-acid batteries	❑ More expensive than lead-acid ❑ Limited long-term potential for cost reductions due to material costs ❑ Toxic components (cadmium)	❑ Utility/Telecom backup ❑ Consumer electronics	❑ Utilities (generation, transmission and distribution) ❑ Consumers	❑ Lower costs ❑ Improved recycling capability

EES Technology	Advantages	Disadvantages	Major Applications	Customer	Potential Improvements
NiMH	❑ Relatively mature technology ❑ Relatively rugged ❑ Higher energy density and ❑ Better cycle life than lead-acid batteries ❑ Less toxic components Ni-Cd	❑ More expensive than lead-acid ❑ Limited long-term potential for cost reductions due to material costs	❑ Utility/Telecom backup ❑ Consumer electronics	❑ Utilities (generation, transmission and Ddistribution) ❑ Consumers	❑ Lower costs ❑ Improved recycling capability
Ultra-capacitors (Electric Double-Layer Capacitors)	❑ High power density ❑ High cycle life ❑ Quick recharge	❑ Low energy density ❑ Expensive ❑ Sloped voltage curve requires power electronics	❑ Power quality ❑ Emergency bridging power ❑ Fluctuation smoothing	❑ Industrial customers ❑ Utilities (distribution utilities with local renewable generation with potential for fluctuations)	❑ Lower costs ❑ Higher energy densities

EES Technology	Advantages	Disadvantages	Major Applications	Customer	Potential Improvements
SMES	❑ High power	❑ Low energy density ❑ Large parasitic losses ❑ Expensive	❑ Power quality ❑ Emergency bridging power	❑ Utilities (IOUs, integrated utilities)	❑ Lower costs ❑ Higher energy densities ❑ Faster recharge
Flywheels	❑ High power density ❑ High cycle life ❑ Quick recharge ❑ Independent power and energy sizing	❑ Low energy density ❑ Large standby losses ❑ Potentially dangerous failure modes`	❑ Frequency regulation ❑ Power quality ❑ Emergency bridging power ❑ Fluctuation smoothing	❑ Industrial customers ❑ Utilities (IOUs, integrated utilities)	❑ Lower costs ❑ Higher energy densities
CAES	❑ Huge energy and power capacity	❑ Geographically limited ❑ Requires fuel input ❑ Long construction time ❑ Large scale only	❑ Energy arbitrage ❑ Frequency regulation ❑ Ancillary services	❑ Utilities (IOUs, integrated utilities)	❑ Adiabatic capability (requires thermal storage)

EES Technology	Advantages	Disadvantages	Major Applications	Customer	Potential Improvements
Pumped Hydro	❑ Huge energy and power capacity	❑ Geographically limited ❑ Expensive to site and build ❑ Long construction time ❑ Large scale only	❑ Energy arbitrage ❑ Frequency regulation ❑ Ancillary services	❑ Utilities (IOUs, integrated utilities)	

Chapter 2: Economics of electric energy storage in New York[4]

2-1. Introduction: NYISO Markets and EES

The New York Independent System Operator (NYISO) administers the wholesale energy markets in New York State. NYISO's electricity markets include installed capacity, energy, and ancillary services. Approximately 45% of New York electricity is transacted in the NYISO day-ahead market, 5% is transacted in the NYISO real-time market, and 50% is transacted through bilateral contracts (NYISO 2005a).

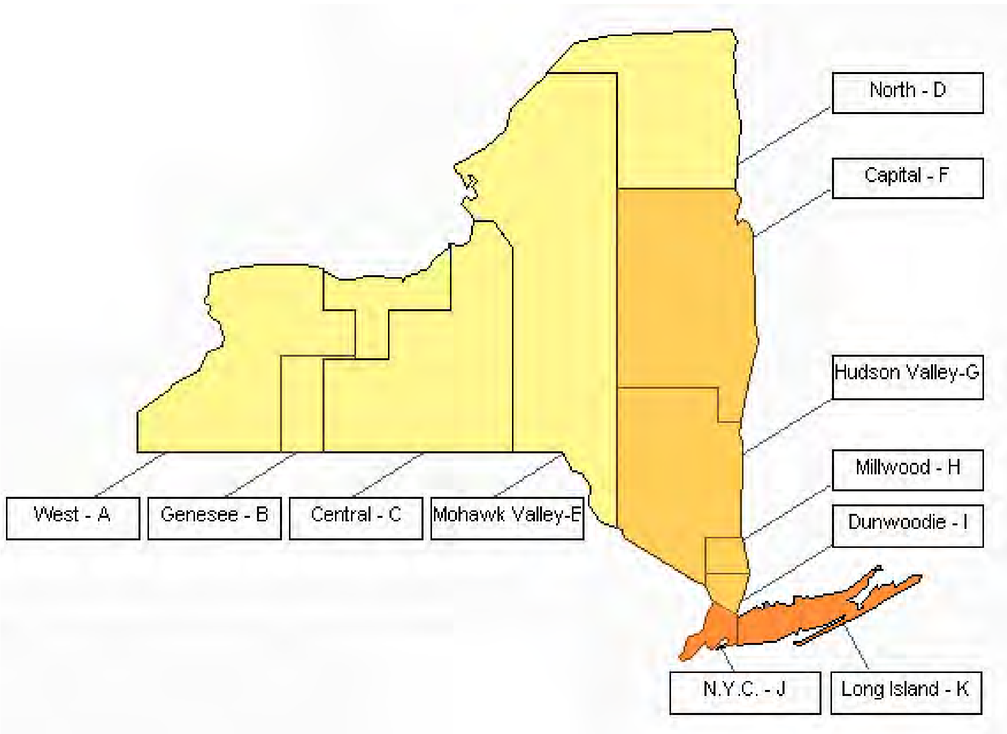

Figure 2-1. The eleven NYISO market zones grouped into three regions. Based on the NYISO LBMP Map © NYISO.

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[4] Significant portions of this chapter appear in: Walawalkar, R., Apt., J. and Mancini, R., 2007. Economics of electric energy storage for energy arbitrage and regulation in New York, Energy Policy 35(4), 2558-2568.

I have aggregated the eleven zones defined by NYISO (Figure 2-1) into three (Table 2-1). These regions are distinct in terms of geography and in energy price distribution. There is a clear similarity in the peak and off-peak prices in the zones in each region. This pattern is observed in all three periods used for this analysis: the complete year, the summer capabilities period, and the winter capabilities period.

Table 2-1. NYISO zones and regions used in this analysis

Region	Zones
NY West	• West (A) • Genesee (B) • Central (C) • North (D) • Mohawk (MH) Valley (E)
NY East	• Capital (F) • Hudson Valley (G) • Millwood (H) • Dunwoodie (I)
New York City	• NYC (J) • Long Island (K)

Table 2-2. NYISO location-based marginal price distribution across zones for 2001-2007.

		Peak ($/MWh)			Off Peak ($/MWh)		
Region	Zone	All Year	Summer	Winter	All Year	Summer	Winter
New York City	Long Island	$82.94	$85.65	$80.19	$59.69	$59.67	$59.70
	NYC	$79.73	$82.51	$76.91	$53.35	$53.34	$53.35
NY East	Capital	$65.32	$65.07	$65.57	$47.46	$45.71	$49.23
	Dunwoodie	$69.62	$72.15	$67.05	$48.40	$47.34	$49.48
	Hudson Valley	$68.06	$70.01	$66.09	$47.82	$46.59	$49.08
	Millwood	$68.98	$71.51	$66.40	$47.98	$46.88	$49.09
NY West	Central	$58.25	$58.75	$57.74	$42.18	$41.15	$43.23
	Genesee	$56.89	$57.48	$56.29	$40.62	$39.58	$41.68
	MH Valley	$60.09	$60.60	$59.58	$43.74	$42.76	$44.75
	North	$57.72	$57.79	$57.64	$42.78	$41.71	$43.86
	West	$54.32	$55.35	$53.27	$38.77	$37.95	$39.60

Table 2-2 lists the distribution of the mean location-based marginal price (LBMP) for different zones and seasons for the 2001-2007 period. Correlation analysis of the zonal LBMP prices was also performed to test the validity of grouping the eleven zones into our three regions. All zones in the NY West region have a correlation coefficient higher than 0.98, and all zones in the NY East region have a correlation coefficient higher than 0.96. New York City and Long Island have a lower correlation coefficient of 0.82, but these zones showed a much greater degree of correlation with each other than with the other zones. Appendix 2-A-1 includes additional tables of mean values of LBMP data for each year from 2001-2007 that justified the grouping of these zones into three regions.

2-2. The analytic framework: market scenario analysis

NYISO has recognized in its market design special resources that have limited electric energy output capability for short time periods and/or require a recharge period (NYISO 2005a). These energy-limited resources (ELRs), which are generally peaking plants or demand-side resources must demonstrate the ability to deliver energy for a minimum of four consecutive hours each day. Thus, NaS batteries can be utilized as ELRs (for energy arbitrage), whereas flywheels cannot. The latter are particularly well-suited for providing regulation service due to the very high cycle life.

The net revenues for each market can be calculated as follows: Energy arbitrage net revenue is the difference between revenue received from energy sale (discharge) during 'N' peak hours and the charging cost for off-peak energy, which includes a factor ($1/\eta$) for additional energy required due to losses, where η is the round-trip efficiency. Let T_{DS} denote the starting hour of discharge, T_{CS} the starting hour of the charging period, $P_{Energy}(t)$ the LBMP price of energy for the corresponding hour, and $Q_{Energy}(t)$ the amount of energy delivered during the hour. Then

$$(2\text{-}1)\ \sum R_{Energy}(t) = \sum_{t=T_{DS}}^{T_{DS+N(energy)}} [P_{Energy}(t) * Q_{Energy}(t)] - \frac{1}{\eta} \sum_{T_{CS}}^{T_{CS+N(energy)}} [P_{Energy}(t) * Q_{Energy}(t)]$$

Regulation and frequency response service revenues are calculated based on the market-clearing price for the regulation service. EES are paid for both charging and discharging when responding to appropriate regulation signals from the ISO. The EES' cost to provide regulation depends on the round-trip efficiency, as EES need to pay for the energy consumed during the regulation cycle.

$$(2\text{-}2) \sum R_{regulation}(t) = \sum_{t=T_{DS}}^{T_{DS+N(regulation)}} P_{regulation}(t) * |Q_{regulation}(t)| - (1-\eta) \sum_{T_{CS}}^{T_{CS+N(regulation)}} [P_{Energy}(t) * |Q_{regulation}(t)|]$$

Appendix 2-A-2 lists the binding constraints for these equations. A global optimization for operation of EES providing a combination of energy and ancillary services would require data such as distribution of hours for operating reserve pickups (the actual delivery of energy by units selected for providing operating reserves) and detailed technical data to analyze the effect of changing operational parameters on capital cost; these data are not yet available. In the next section I examine the economics of EES under different scenarios by comparing the net revenues that can be generated from a 1 MW EES for different applications.

2-3. Energy arbitrage revenues

I have analyzed the energy arbitrage potential of energy-limited resources for energy delivery times of 10 hours, 4 hours, and 2 hours. These periods of energy arbitrage were selected based on two criteria: First, EES technologies considered for long-duration energy arbitrage have efficiencies between 65% and 85% (the ratio of input power to output power is ~ 1.2 - 1.4). Assuming that these units are charged and discharged at the same rate, this results in 20-40% additional charging time, limiting the maximum duration for energy sale to 10 hours. Second, NYISO allows EES participating under the energy-limited resources program to receive capacity credits if they can provide energy for 4 successive hours (NYISO 2005a). Thus for an application with energy arbitrage as the only service, 4 hours of energy discharge capability was considered as the minimum duration necessary for market participation.

NYISO market energy data from 2001-2004 were used to determine the statistical net revenue potential for three different operating conditions (2-hour, 4-hour, and 10-hour). For determining the net revenues, the maximum potential revenue period and the minimum potential cost period for each day in the three regions were determined. Appendix 2-A-3 provides details of the analysis.

The maximum electricity price period has a relatively wide distribution and shows a seasonal shift in the maximum revenue period. The maximum revenue period for 4-hour energy arbitrage is from 12 a.m. to 4 p.m. in the summer period, and shifts to 3 p.m. to 7 p.m. in the winter period. This information was used in calculating the anticipated revenues by using the LBMP for corresponding hours. Under the base scenario it was assumed that a market participant will bid in the EES resources based on the historical data for the seasonal forecast for peak hours. With the use of better forecasting tools utilizing weather data, load forecasts, and historical prices, market participants may be able to increase revenue by capturing peak and least-cost periods on a weekly or even daily basis.

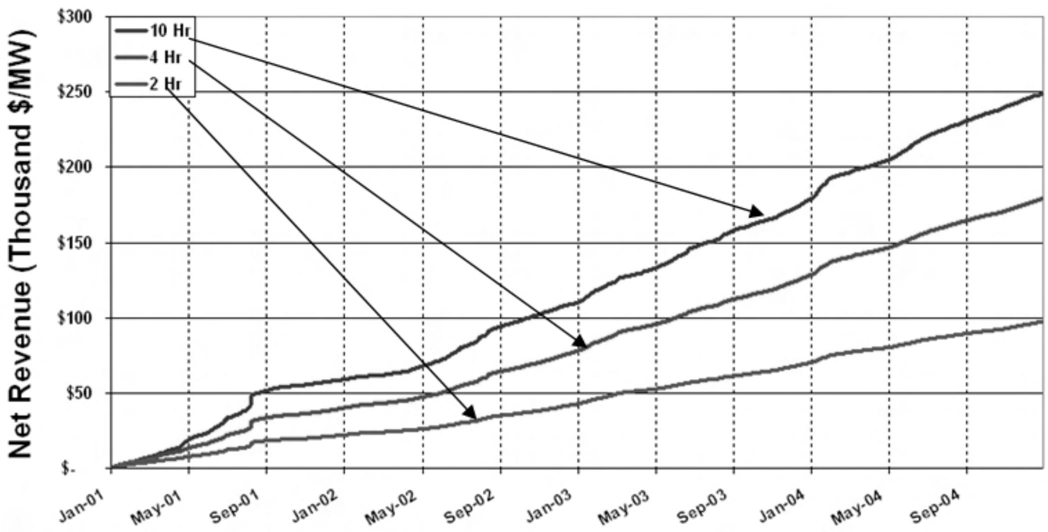

Figure 2-2. Cumulative net revenue (2001-2004) from energy arbitrage in New York City.

Figure 2-2 shows the potential cumulative net revenues (i.e. the difference between the energy revenues and the charging cost) for different durations of energy arbitrage in the New York City region during the 2001-2004 period. The total net revenue was determined by using a 1-MW-sized energy storage unit for 10-hour, 4-hour, and 2-hour energy arbitrage. The base case efficiency was initially assumed to be 83% (a ratio of input energy to output energy of 1.2). For this efficiency, 10-hour energy arbitrage would have generated approximately $250,000 of revenue during the 2001-2004 period in New York City. The energy arbitrage revenues for 4-hour and 2-hour sales would have been approximately $170,000 and $100,000 respectively.

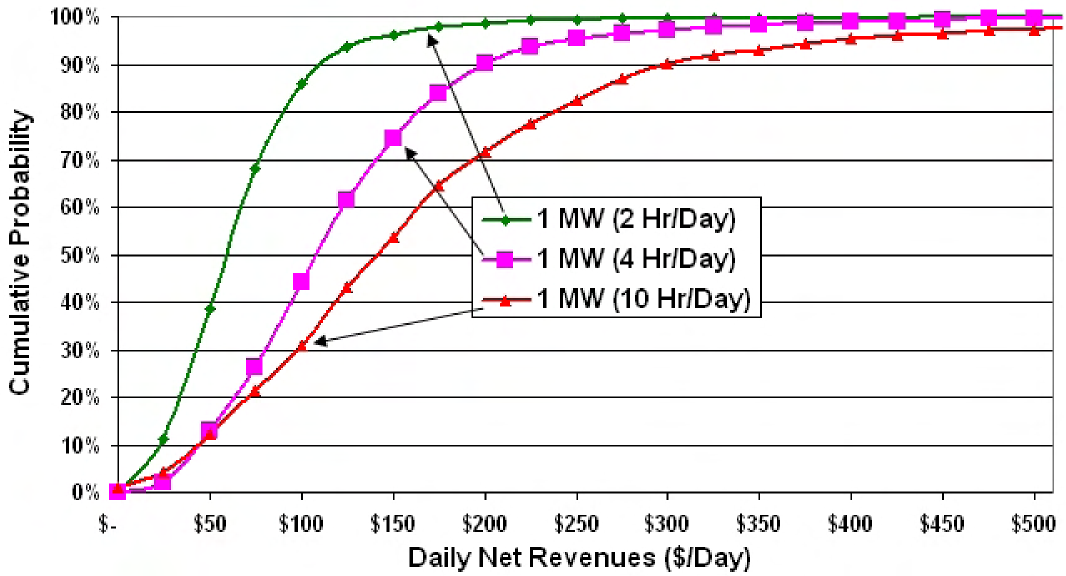

Figure 2-3. Cumulative probability distribution of daily net revenues for energy arbitrage in New York City.

Figure 2-3 shows the cumulative probability distribution of daily net revenues that would have been received during 2001-2004 by EES for energy arbitrage for 2-hour, 4-hour, and 10-hour periods. Although the marginal net revenue from operating the unit for shorter durations (2 or 4 hours) is significantly higher than from operating the unit for 10 hours, the operator receives more total daily revenue when the units are run for a longer duration. There is a 50% probability that the EES will receive over $50/MW-day in net revenues for 2- hour energy arbitrage. This net revenue increases to over $105/MW-day for 4-hour and $140/MW-day for 10-hour operations.

If the power rating of EES and the rate of discharge are not limiting factors, then an EES with a 10 MWh energy capacity could theoretically be operated at higher power levels for shorter periods of time. A unit might be used for energy arbitrage delivering 1 MW for 10 hours, 2.5 MW for 4 hours, or 5 MW for 2 hours. In practice, operations would be limited by the unit's power rating and the power conversion system. A more detailed analysis involving capital cost estimates is required to determine if it is more economical to deploy EES units that are able to provide 2 to 4 hours of required energy at higher power levels.

2-4. Effect of round-trip efficiency

The net revenue from energy arbitrage is highly sensitive to EES efficiency because inefficient systems are forced to buy some peak power. Figure 2-4a shows the expected net revenues from energy arbitrage for 2001-2004 in the New York City region from a 1-MW EES, as a function of efficiency. In New York City, an EES with round-trip efficiency of less than 73% would earn more net revenues for 4-hour energy arbitrage than for 10-hour.energy arbitrage. An EES unit with efficiency of less than 67% would earn more net revenues from 2-hour energy arbitrage than from 10-hour energy arbitrage. Lower round-trip efficiency means that the EES must be charged for longer duration, increasing charging costs and reducing the price differential between peak and off-peak operation. Due to the different energy prices in the three regions, the switchover points between these operating modes occur at slightly different efficiencies for the various geographic regions. Figure 2-4b shows a similar graph for the NY West region.

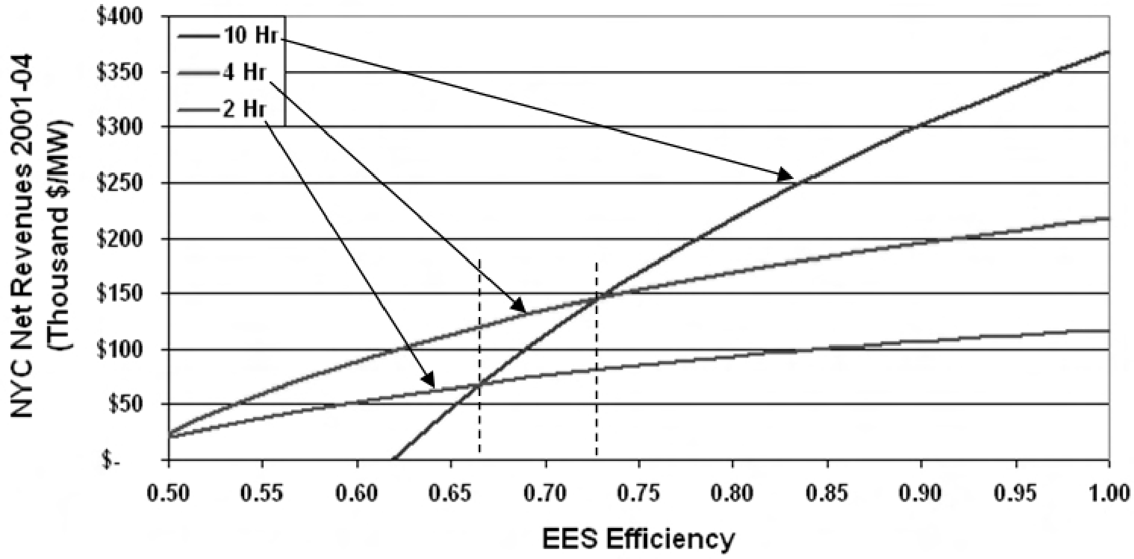

Figure 2-4a. Cumulative net revenues as a function of EES efficiency in the New York City region.

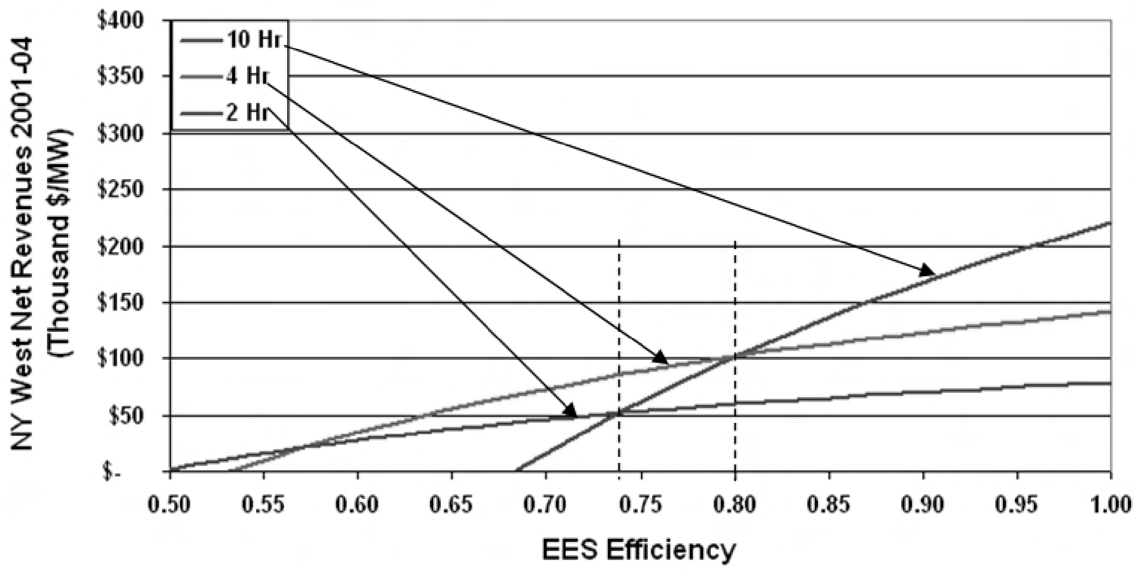

Figure 2-4b. Cumulative net revenues as a function of EES efficiency in the New York West region.

The net revenue from energy arbitrage is highly sensitive to the round-trip efficiency of the EES. Round-trip efficiency can be used to determine the energy rating of the EES and the maximum duration of energy arbitrage that can operated economically.

2-5. Installed Capacity Market (ICAP)

ICAP revenues are a way to encourage new additions of generation capacity in areas with tight supply reserve margins. Any EES capable of providing four hours or more of capacity can generate ICAP revenues in addition to the revenues received from energy or ancillary markets. Table 2-3 shows the summary results for the ICAP monthly market auctions for 2004-2005. There are also locational requirements for New York City (zone J) and Long Island (zone K) that require Load Serving Entities (LSE) serving these areas to procure a certain percentage (80% and 99% respectively) of the regional peak load from resources within the individual zones (NYISO, 2005a). Due to this locational requirement, the ICAP revenues for the NYC region are significantly higher than for the rest of the state and contribute significantly towards making EES operations economical in this region.

Table 2-3: ICAP Revenues 2004-2007 (NYISO, 2008b)

	Minimum Market clearing price ($/kW-Month)	**Average Market clearing price ($/kW-Month)**	**Maximum Market Clearing Price ($/kW-Month)**
New York City	$5.60	$9.07	$12.54
Rest of State	$1.58	$2.29	$3.00

2-6. Regulation Revenue

EES can be used for providing various required ancillary services:1) regulation services required to track moment-to-moment fluctuations in load and supply and 2) reserve services for meeting intra- and inter-hour changes in the supply and load curves (NYISO 2005b).

Regulation and frequency response services assist in maintaining the system frequency at 60 Hz and allow compliance with reliability criteria set by NERC, the New York State Reliability Council (NYSRC), and the Northeast Power Coordinating Council (NPCC).

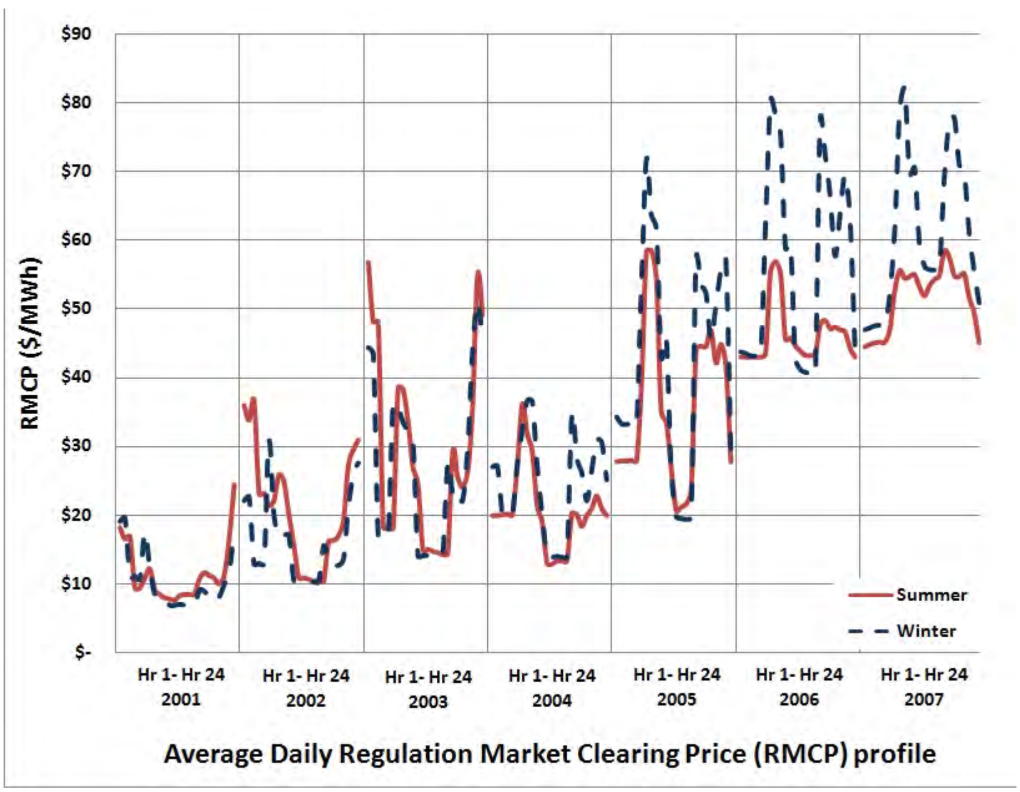

Figure 2-5. Average daily regulation market clearing price (RMCP) profiles for NYISO during 2001-2007.

Resources providing regulation service are directed to move from each real-time dispatch base point (usually every 5 minutes) in 6-second intervals at their stated ramp rate (Hirst 2001). Figure

2-5 shows the average daily regulation market-clearing price (RMCP) profiles for the years 2001-2007. These curves show the average RMCP price for each hour of the day during the year for the summer capabilities period and the winter capabilities period. During both the summer and winter capabilities periods the regulation prices are higher than average during the morning pickup and evening drop-off hours, when the system load changes rapidly. In recent years the value of regulation during these peak periods has been significantly higher during the winter months than during the summer months due to higher fuel prices.

Resources can participate in the regulation market if they have automatic generation control capability within the New York control area. Some EES technologies, particularly flywheels, can be used to offer regulation services. Flywheels cannot be utilized for energy applications due to their short duration (15-minute) energy storage capacity. For pumped hydro facilities, Perekhodtsev (2004) has shown that frequency regulation can offer one of the highest value markets for storage. In NYISO, our work shows that regulation offers the maximum revenue potential among all the ancillary services, followed by spinning, non-spinning, and 30 minute operating reserves (Walawalkar et al. 2005). Figure 2-6 shows the annual average price for regulation and spinning reserves for NYISO from 2001 to 2007.

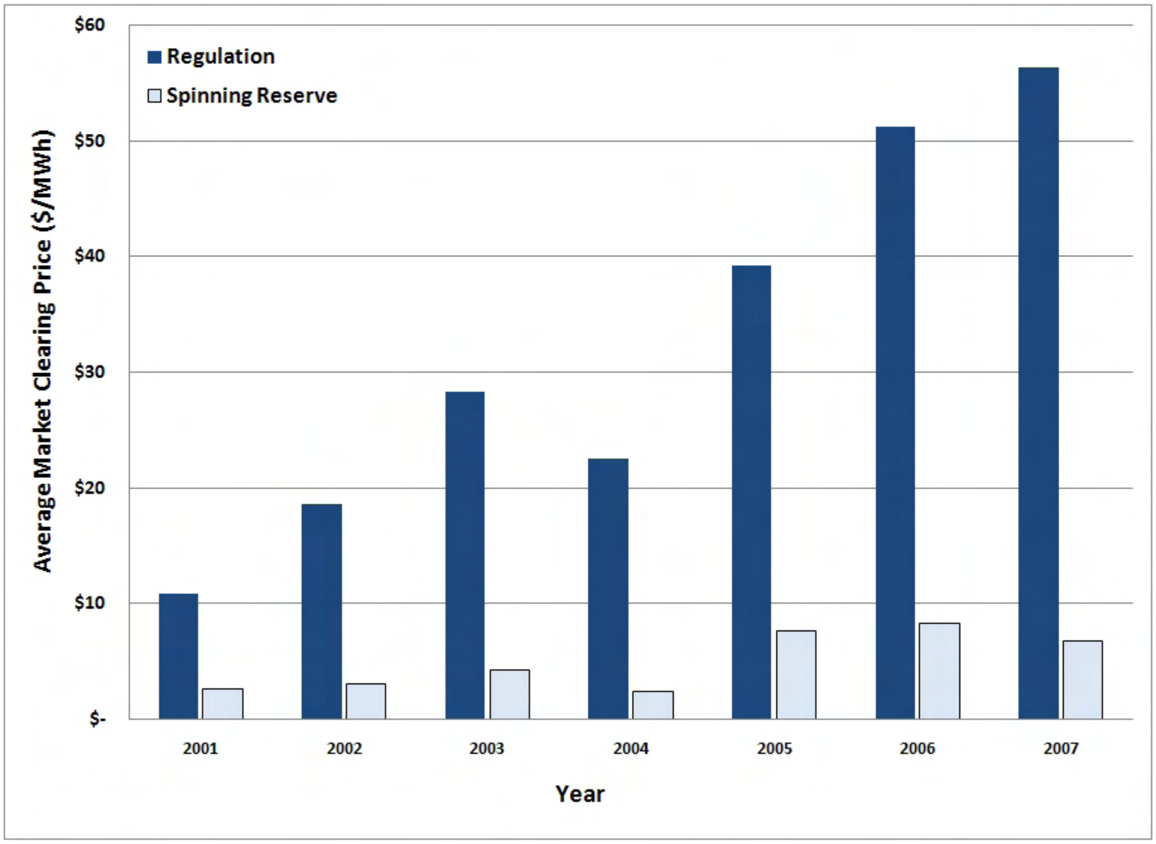

Figure 2-6. Annual average regulation and 10-minute spinning reserve prices for NYISO (2001-2007)

2-7. EES Economics

Table 2-4 summarizes the expected net revenue for energy arbitrage (with round-trip efficiency of 75%) and regulation in all three regions. The maximum-case scenario represents the data from the year with maximum net revenues (2006), whereas the minimum-case scenario represents the year with minimum net revenues (2003). The estimates for average net revenues were calculated using the average revenue and cost figures from 2001-2007 market data. (NYISO, 2008a)

Table 2-4. Summary of potential annual net revenues for various applications by region.

Application	**Expected Net Revenue (Thousand $/MW-year)**		
	New York City ***Min - Avg - Max***	***NY East*** ***Min - Avg - Max***	***NY West*** ***Min - Avg - Max***
Energy Arbitrage 10 Hours*	$91 - $150 - $192	$26 - $47 - $66	$22 - $35 - $44
Energy Arbitrage 4 Hours* + Synchronous Reserve 15 Hours	$112 - $189 - $254	$57 - $89 - $125	$46 - $75 - $102
Regulation 24 Hours	$59 - $201 - $370	$67 - $212 - $389	$75 - $222 - $401

*** Includes capacity revenue.**

New York City has the highest revenue potential for energy arbitrage of the three regions in New York State. In NY East and NY West, regulation services have the maximum revenue potential and the lowest uncertainty (regulation prices have less variance than energy prices). However, there is some regulatory uncertainty in utilizing flywheels for regulation services. Flywheels have much smaller regulation capacity per installation and rely on the changing sign of the regulation control signal, so that the unit can be continuously charged and discharged (i.e., an average zero net energy regulation signal). Currently flywheel manufacturers and NYISO officials are trying to develop ways to determine an appropriate evaluation criterion for calculating the performance of flywheels for regulation services. (The original evaluation criteria were devised for large central generators providing regulation services by the use of automated generation controls.)

Appendix 2-A-4 provides a summary of the scenario analysis conducted to estimate the emission impact from 500 MW of EES installations in NYC for energy arbitrage operations. The motivation behind this scenario analysis was to determine if there are net social benefits of reducing emissions from peak generation from NYC region to upstate NY during off peak hours. The social benefit or cost of such energy arbitrage operation depends on the type of generation displaced from during peak hours and the type of generation utilized for charging EES during off peak hours.

2-8. Additional Benefits

Since most current installations of EES are based on the valuation of the benefits offered by EES for either power reliability or system upgrade cost deferral, I have roughly quantified these benefits based on a review of the literature. The benefits accrue to different market participants. For example, the deferral of system upgrade costs is important to utilities or LSEs, whereas commercial and industrial customers value the power quality and reliability benefit (Butler et al. 2003; EPRI 2003; Eyer et al. 2004).

- ***Power quality and reliability*: The benefits of power quality and reliability depend on the monetary cost associated with power system events that can cause customer interruptions. For commercial and industrial customers, one estimate for annual outage hours is 2.5 hours per year and a value-of-service of $20/kWh (Eyer et al. 2004). Thus the annual reliability benefit is $50/kW-year or $50,000/MW-year. Similarly, power quality benefits can be calculated based on a survey of existing research and known data related to power quality. Earlier studies indicate a benefit of $5/kW-event and 20 events per year, or $100,000/MW-year (Eyer et al.,2004). Combined power quality and reliability benefits can thus be estimated as $150,000/MW-year. These are societal benefits and are difficult for an EES operator to capture except when an EES is utilized at a customer facility to provide power quality and reliability. In certain cases in regulated markets, the regulator may allow recovery of EES costs related to power quality and reliability.

- **System upgrade cost deferral:** A properly located EES can allow utilities to defer transmission and distribution upgrade costs. Such suitable locations can be characterized by infrequent maximum load days with peak load occurring during only a few hours in a day. Also locations with slow load growth can utilize an EES for a few years to defer T&D upgrade. These benefits could range from $150,000 - $1,000,000/MW-year (EPRI 2003; Eyer et al. 2004).

2-9. Net present value analysis

Based on the range of annual net revenue estimates and the EES cost data, the net present value (NPV) was calculated for various EES technologies in different regions to evaluate the economics of these technologies. The discount rate used was 10%, and the project life considered was 10 years. Table 2-5 provides summary of all financial parameters used in the NPV simulations.

Table 2-5: Summary of financial parameters

	NaS Battery	Flywheel
Capital Cost ($/kw)	$1,500-$2,000-$3,000	$750-$1,500-$2,000
O&M Cost ($/kw-yr)	$30	$25
Disposal cost ($/kw)	$15	-
Round-trip Efficiency	75%	85%
Discount factor	10%	10%

I performed Monte Carlo simulations which used NYISO market data to study the effect of capital cost, round-trip efficiency, and location on the distribution of NPV. This simulation was performed for 1,000 iterations using a triangular distribution for the net revenue for 4-hour energy arbitrage combined with 15 hours of synchronized reserve for a NaS battery in all three regions. Similar simulations were also performed for flywheels using a triangular distribution of net revenue from regulation. The minimum, maximum, and average values for net revenue were selected for each region based on the data presented in Table 2-4. The minimum revenue was for year 2002, maximum revenue was for year 2005 and 2001-2007 average revenue was used for the average value of the triangular distribution. To be conservative, I used $150,000/MW-year as the average value for the system upgrade deferral or power quality and reliability benefit of NaS, and $100,000/MW-year as the average value for the power quality benefits of flywheels to augment the revenues that can be realized by a typical market participant in New York.

A sensitivity analysis performed on the various financial parameters for calculating NPV of NaS batteries for energy arbitrage indicate that the T&D benefits, capital costs and annual revenues are the top 3 factors influencing the NPV of project. Appendix 2-A-5 shows the details of the sensitivity analysis.

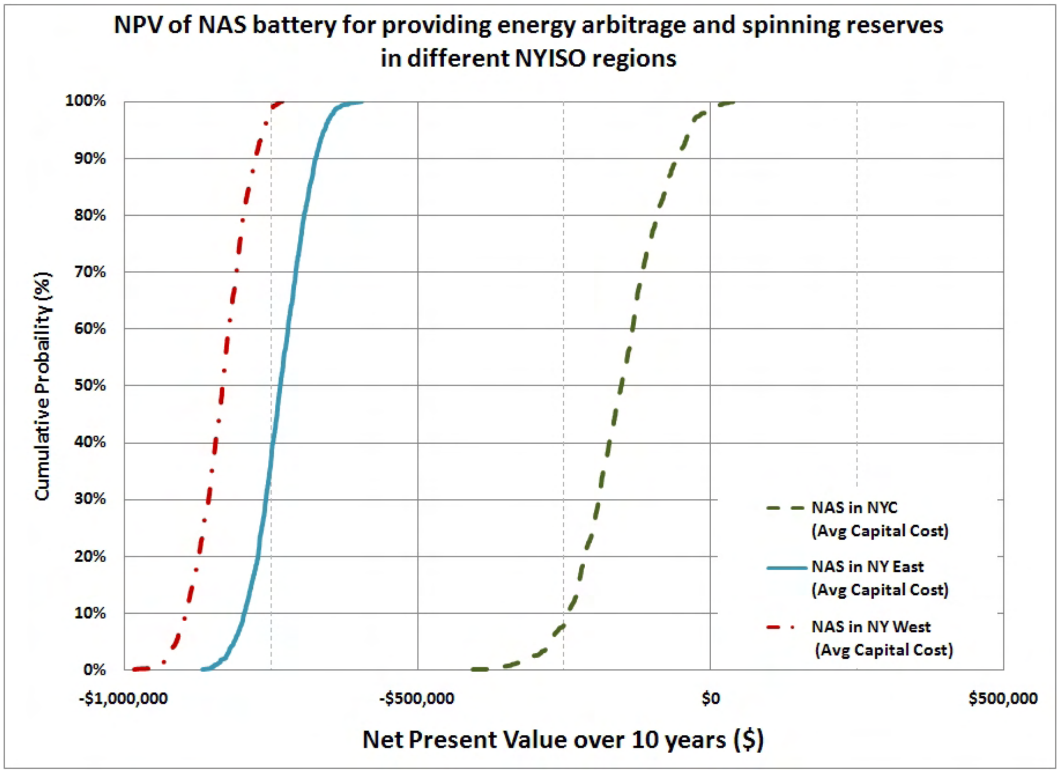

Figure 2-7a: Effect of the location of an installation on the cumulative probability distribution of NPV for a NaS installation for 4-hour energy arbitrage and 15 hours of spinning reserves across NYISO regions with average capital cost.

Figure 2-7a shows the NPV distribution for a NaS installation in all three regions using the average cost estimates for capital and operation and maintenance (O&M) costs for a NaS installation. From Figure 2-7a, it can be seen that for the expected capital cost of $2000 / KW, the NPV is negative in all three regions, including New York City, where the operating revenues are significantly higher than other regions due to higher capacity credits and energy prices. Figure 2-7a shows that the mean NPV for a NaS installation in New York City is approximately -$150,000, whereas similar units in NY East and NY West have mean NPVs of -$730,000 and -$830,000, respectively. The major factor contributing to the uncertainty of the NPV of the project is the variation in the energy revenues and charging costs from the actual market data.

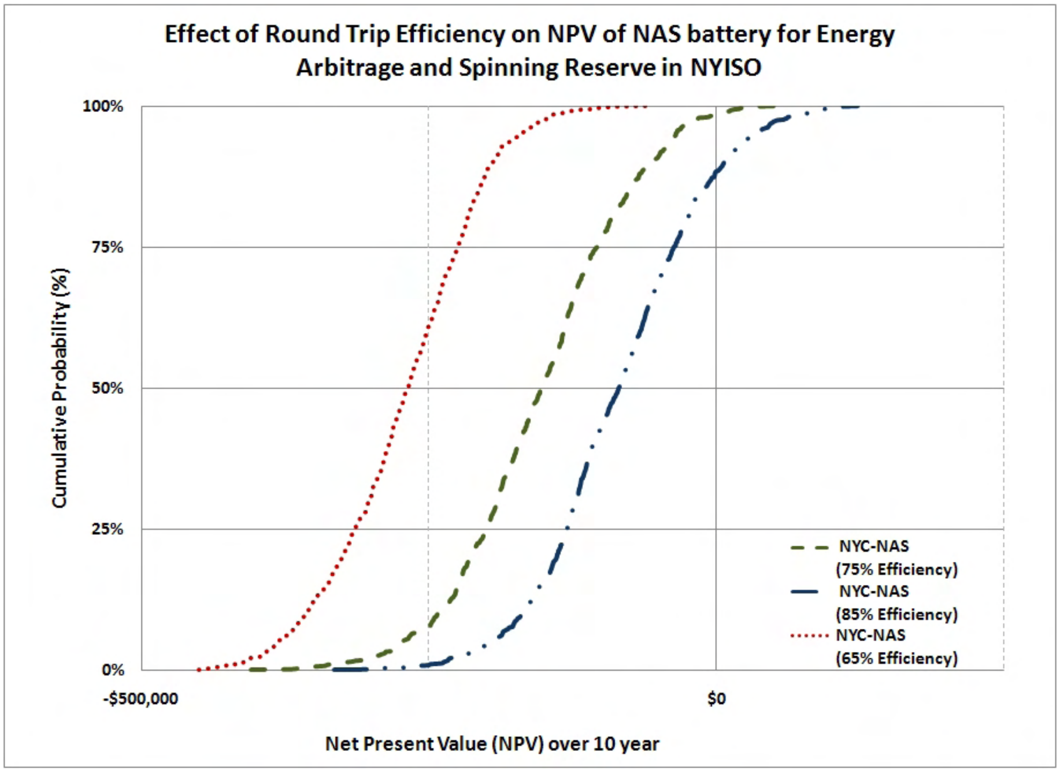

Figure 2-7b: Effect of round-trip efficiency on the cumulative probability distribution of NPV for a NaS installation for 4-hour energy arbitrage and 15 hours of spinning reserves in NYC with average capital cost.

Since the net revenues from energy arbitrage are significantly affected by the round-trip efficiency of the EES, I performed additional simulations to evaluate the effect of change in round-trip efficiency on the NPV of a NaS installation for energy arbitrage and spinning reserve in NYC. The results of the simulation are shown in figure 2-7b. Although with higher round-trip efficiency of 85% there is a 12% probability that the NaS installation in New York City would have a positive NPV, the mean NPV was approximately -$85,000. The mean NPV dropped to -$270,000 for a round-trip efficiency of 65%.

I also performed simulations to understand the effect of the capital cost on the NPV of a NaS battery. Figure 2-7c shows the results of Monte Carlo simulations performed for three scenarios of capital cost estimates using an average round-trip efficiency of 75%. I used $1,500/KW as a best-case scenario and $3,000/KW for a scenario with a higher than expected capital cost estimate. With the best-case scenario,the mean NPV for NaS installation is approximately $350,000, whereas in the worst-case scenario the mean NPV is -$1,150,000.

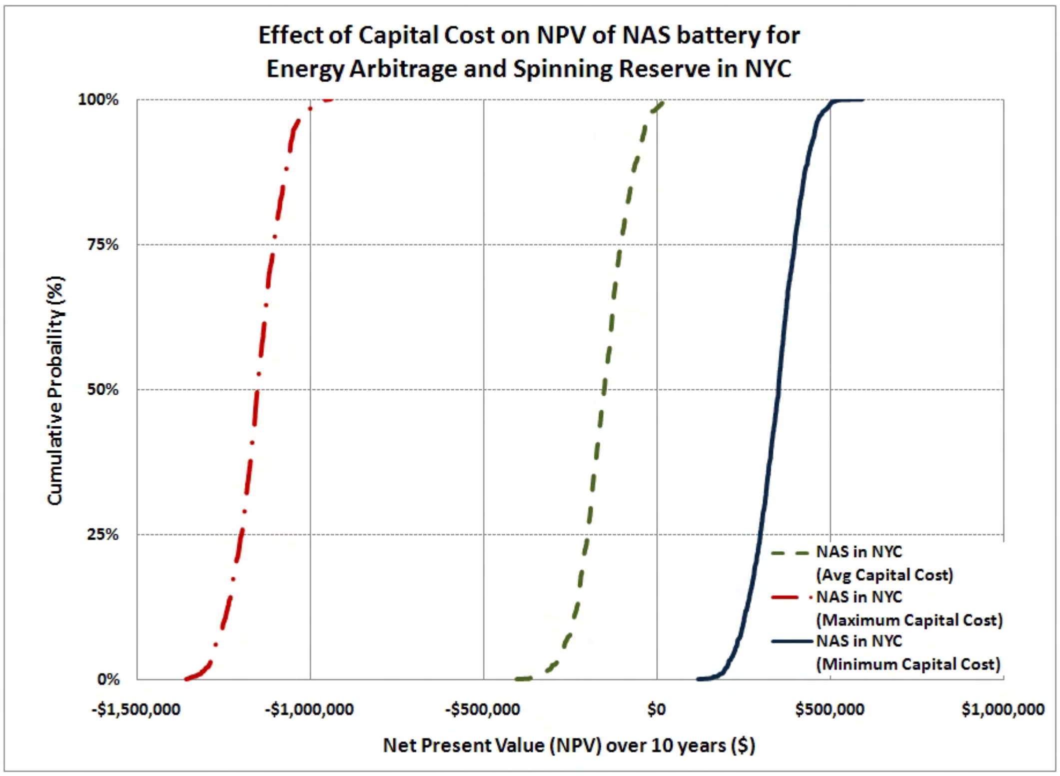

Figure 2-7c: Effect of capital cost on the cumulative probability distribution of NPV of NaS for 4-hour energy arbitrage and 15 hours of spinning reserves in NYC.

Next, I compared the NPV of flywheels for providing 24-hour regulation in NY West (with the highest net revenues for regulation) to the NPV of a NaS in NYC with average cost and average round-trip efficiency. I used the capital cost estimate of $1,500/KW for flywheels with a round-trip efficiency of 85% as a base-case scenario. The results shown in Figure 2-8a suggest that there is a less than 1% probability of a negative NPV when flywheels are used for providing regulation in the NY West region. The mean NPV of using flywheels with a round-trip efficiency of 85% for regulation in NY West is $390,000.

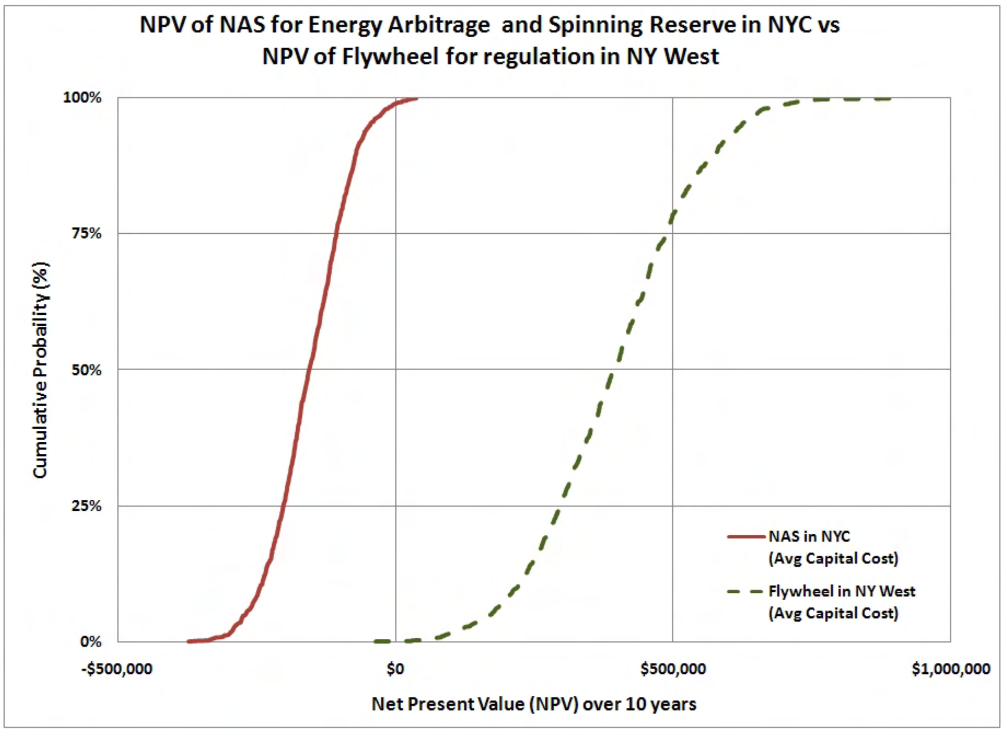

Figure 2-8a: Comparison of the distribution of the NPV for flywheels used for 24-hour regulation in NY West and an NaS battery used for 4-hour energy arbitrage and spinning reserve in New York City.

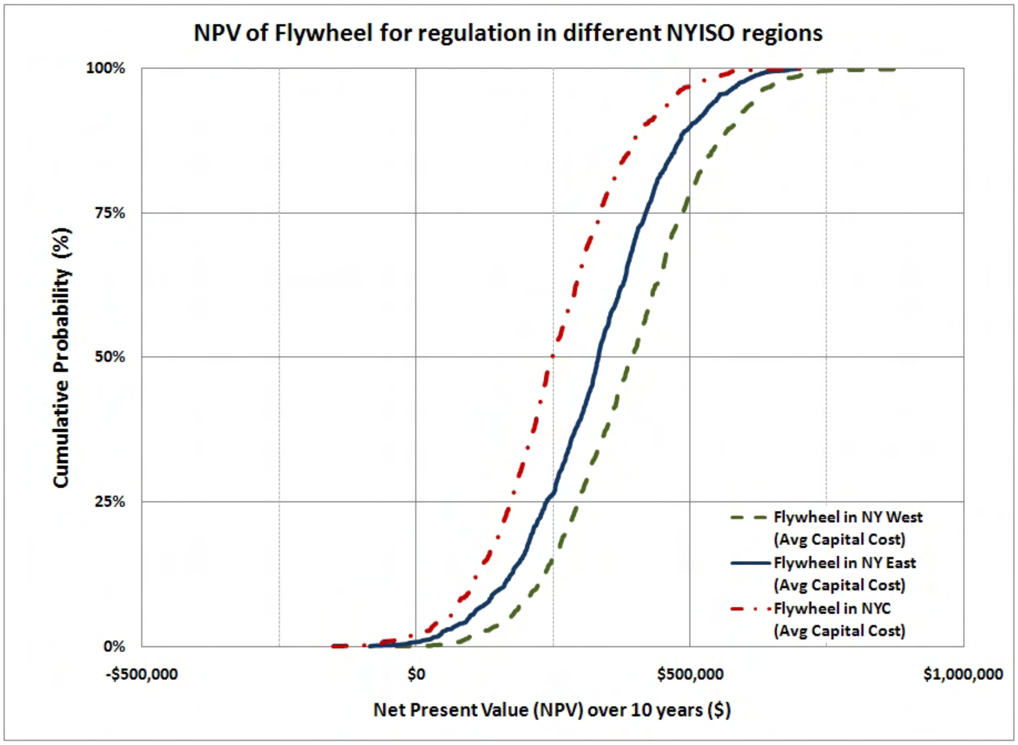

Figure 2-8b: Effect of location on the cumulative probability distribution of the NPV of flywheels for regulation in NYISO.

Figure 2-8b shows the results of the Monte Carlo simulations to analyze the effect of location on the NPV of flywheels for providing regulation in NY. Since the regulation market-clearing price (RMCP) is same across the NYISO, the difference in the NPV for providing regulation reflects energy costs to cover round-trip losses due to the differences in energy prices in these regions. Due to these higher energy costs, the mean NPV of flywheels for providing regulation drops to $330,000 and $250,000 respectively, in NY East and NYC region.

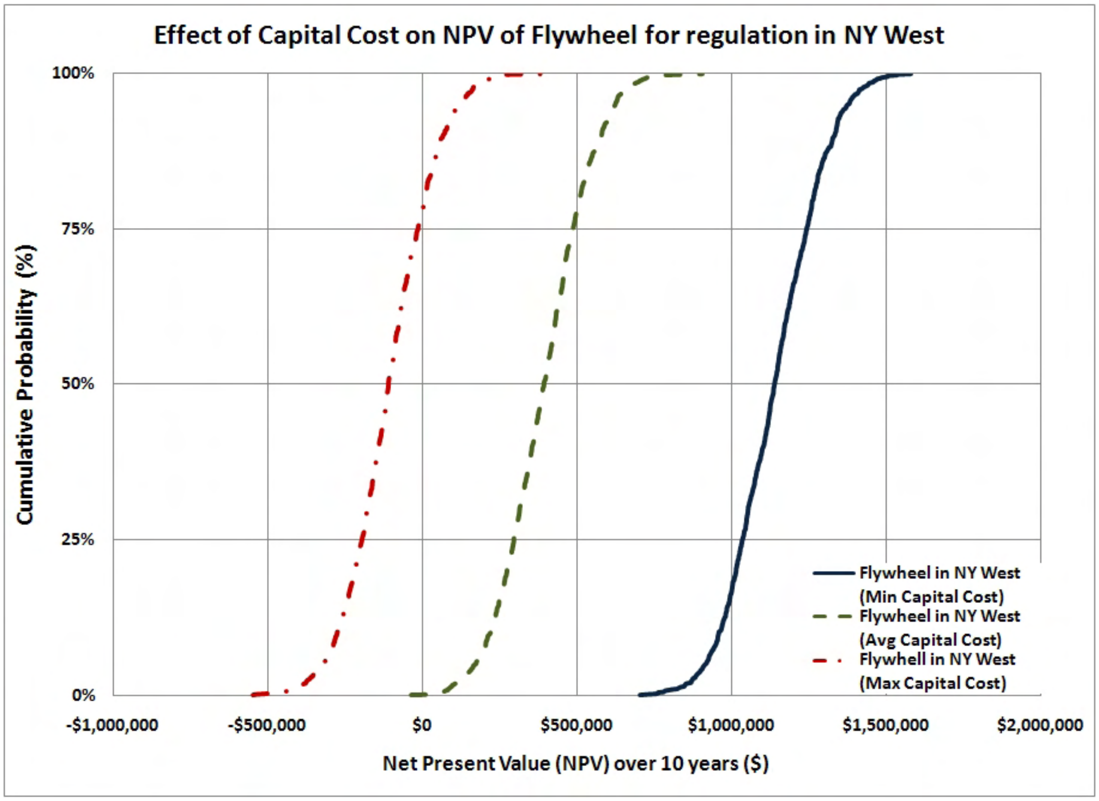

Figure 2-8c: Effect of capital cost on the cumulative probability distribution of NPV of flywheels for providing regulation in NY West.

Similar to NaS batteries, capital cost has a significant impact on the NPV of using flywheels for regulation in NY. Figure 2-8c indicates that for a scenario with the capital cost of flywheels at $2,000 /KW instead of $1,500/KW in the base-case scenario, the mean NPV from providing 24 hours of regulation dropped to -$110,000. On the other hand, in the best-case scenario of $750/KW as the capital cost, the mean NPV increased to $1,140,000 from the base-case scenario of $390,000.

2-10. Conclusion

EES technologies capable of discharging at higher power and energy densities than conventional lead-acid batteries can offer benefits to various market participants in competitive electricity markets. There are technical as well as market barriers for the wide-scale integration of electric energy storage for wholesale market applications. At present, most energy storage technologies have higher capital costs than peaking power alternatives such as gas turbines (flywheels are similar in capital cost to a combined-cycle natural gas turbine, and NaS batteries have two to four times the capital cost of an NGCC unit). While capital costs are falling somewhat due to technology improvements, significant manufacturing economies of scale have not yet been realized (EPRI 2003; 2004).

Based on market data from 2001-2007, I find that flywheels in the NY West region have a high probability of positive NPV for regulation. Significant opportunities exist in the NY East and NYC regions for regulation. I find that the market-based revenue streams are not sufficient to justify investment in NaS batteries for energy arbitrage and spinning reserves. There still may be opportunities for NaS in locations where the system upgrade deferral benefits are significantly higher than our conservative estimates used in this analysis.

EES units which require an average zero net energy regulation signal are sometimes denied participation in regulation markets. The New York State Research and Development Authority (NYSERDA) and the California Energy Commission (CEC) have initiated efforts to evaluate the performance of flywheels for providing regulation services in recent years. The results of these studies may support the wide deployment of such devices. Current market rules also do not permit most EES technologies to participate in 10-minute synchronous spinning reserve markets, which can offer roughly 15% of the revenue available from regulation (Walawalkar et al. 2005).

A recent analysis (Butler et al., 2003) argued that EES systems with low round-trip efficiency and low equipment cost would be quite viable for energy arbitrage. This research also indicates that achieving lower costs is critical for improving the economics of NaS batteries for energy arbitrage. At the same time, reducing capital costs by sacrificing efficiency can have a significantly adverse effect on the economics of the project, particularly for energy arbitrage. Thus while designing and developing EES systems for electricity market participation, it is crucial to maintain or increase efficiency while reducing the capital cost.

There are several factors that may improve the economics of energy arbitrage in future. First, increased fuel prices for oil and natural gas can result in higher on peak prices. At the same time NY is expecting more than 3000 MW of wind to be integrated in the NYISO system by 2012. As the maximum wind output may be available during the low load hours at night or early mornings, this could put downward pressure on off peak prices in NY. These 2 factors together can result in higher net revenues for energy arbitrage which could substantially improve the economics of NaS batteries in NY in the future.

On the other hand, potential implementation of a price on carbon dioxide emissions may result in higher increases in off peak prices than peak prices due to due to the higher carbon content of coal typically used as fuel for base load plants (Newcomer et. al. 2008). This can result in lower net revenues from energy arbitrage, thus weakening the economic case for NaS further.

The likely greater share of intermittent renewable resources in grid may increase the requirement for regulation, which in turn should result in higher regulation prices. This could further enhance the economic case for use of flywheels for regulation.

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Appendix 2-A-1. Regional distribution of energy prices

Appendix 2-A, shows the summary of the statistical analysis of the zonal LBMP prices for 11 NYISO zones for different periods: the complete year, the summer capabilities period, and the winter capabilities period based on 2001-2007 data.

For NYISO's operations, the peak period is defined as the hours between 7 am and 11 pm inclusive, prevailing Eastern Time, Monday through Friday, except for North American Electric Reliability Council (NERC)- defined holidays. The off-peak period is defined as the hours between 11 pm and 7 am, prevailing Eastern Time, Monday through Friday; all day Saturday and Sunday; and NERC-defined holidays. NYISO has defined the summer capability period as May 1 through October 31 and the winter capability period as November 1 through April 30.

Table 2-A-1. Regional Distribution of Peak LBMP Prices ($/MWh) for 2001-2007.

Region	Zone	2001	2002	2003	2004	2005	2006	2007
New York City	Long Island	$59.78	$57.48	$73.53	$72.23	$113.39	$100.68	$103.67
	NYC	$56.39	$55.43	$77.42	$76.41	$112.53	$86.07	$93.94
NY East	Capital	$49.45	$46.23	$60.23	$60.41	$89.98	$70.43	$80.57
	Dunwoodie	$52.65	$47.69	$61.82	$62.30	$95.83	$78.86	$88.28
	Hudson Valley	$51.97	$46.70	$61.26	$60.96	$92.85	$76.52	$86.27
	Millwood	$51.79	$46.80	$61.19	$61.48	$95.03	$78.50	$88.16
NY West	Central	$43.74	$38.85	$55.08	$55.72	$81.36	$63.57	$69.44
	Genesee	$42.25	$38.00	$54.33	$55.21	$79.88	$62.01	$66.58
	MH Valley	$44.91	$39.69	$56.79	$57.43	$83.85	$65.90	$72.13
	North	$43.29	$38.31	$55.10	$55.54	$80.63	$62.56	$68.63
	West	$41.48	$36.37	$51.47	$52.22	$76.07	$58.67	$63.97

Table 2-A-2. Regional Distribution of Peak LBMP Prices ($/MWh) for the Summer Capabilities Period 2001-2007.

Region	Zone	2001	2002	2003	2004	2005	2006	2007
New York City	Long Island	$59.29	$66.51	$69.32	$72.28	$127.85	$105.91	$98.54
	NYC	$58.59	$63.69	$72.88	$73.80	$126.82	$89.71	$92.31
NY East	Capital	$50.60	$51.93	$55.44	$58.54	$97.24	$67.82	$74.08
	Dunwoodie	$55.35	$52.86	$59.00	$61.23	$107.06	$82.26	$87.40
	Hudson Valley	$54.52	$51.82	$57.85	$59.72	$102.89	$78.84	$84.50
	Millwood	$54.38	$52.02	$58.23	$60.48	$106.50	$81.89	$87.17
NY West	Central	$45.32	$41.80	$51.02	$53.68	$88.97	$62.98	$67.62
	Genesee	$43.95	$40.84	$50.40	$52.83	$87.46	$62.11	$64.95
	MH Valley	$46.60	$42.47	$52.52	$55.14	$91.49	$65.64	$70.50
	North	$44.92	$40.69	$50.76	$52.58	$87.41	$61.62	$66.72
	West	$43.53	$39.97	$47.57	$50.24	$84.21	$59.14	$62.90

Table 2-A-3. Regional Distribution of Peak LBMP Prices ($/MWh) for Winter Capabilities Period 2001-2007.

Region	Zone	2001	2002	2003	2004	2005	2006	2007
New York City	Long Island	$60.29	$48.24	$77.84	$72.17	$98.82	$95.27	$108.93
	NYC	$54.13	$46.97	$82.07	$78.96	$98.12	$82.31	$95.60
NY East	Capital	$48.27	$40.38	$65.15	$62.23	$82.66	$73.12	$87.22
	Dunwoodie	$49.89	$42.39	$64.72	$63.34	$84.51	$75.35	$89.18
	Hudson Valley	$49.37	$41.46	$64.75	$62.17	$82.73	$74.13	$88.09
	Millwood	$49.14	$41.45	$64.22	$62.45	$83.47	$74.99	$89.17
NY West	Central	$42.12	$35.83	$59.23	$57.71	$73.69	$64.18	$71.31
	Genesee	$40.50	$35.09	$58.35	$57.53	$72.25	$61.91	$68.25
	MH Valley	$43.18	$36.84	$61.17	$59.67	$76.15	$66.17	$73.80
	North	$41.63	$35.87	$59.55	$58.42	$73.80	$63.52	$70.59
	West	$39.38	$32.69	$55.47	$54.14	$67.88	$58.18	$65.06

Table 2-A-4. Regional Distribution of Off-Peak LBMP Prices ($/MWh) 2001-2007.

Region	Zone	2001	2002	2003	2004	2005	2006	2007
New York City	Long Island	$38.51	$39.42	$53.09	$54.89	$86.13	$73.50	$72.21
	NYC	$35.40	$37.92	$51.82	$51.33	$76.60	$57.72	$62.62
NY East	Capital	$32.71	$32.23	$43.87	$44.97	$66.62	$52.22	$59.55
	Dunwoodie	$33.09	$32.41	$44.18	$45.68	$68.90	$53.85	$60.66
	Hudson Valley	$33.03	$32.36	$44.04	$44.98	$67.06	$53.21	$60.05
	Millwood	$32.60	$32.00	$43.64	$45.14	$68.21	$53.62	$60.60
NY West	Central	$29.56	$28.20	$39.84	$41.02	$60.06	$46.43	$50.15
	Genesee	$28.48	$27.50	$39.17	$40.50	$58.46	$44.99	$45.25
	MH Valley	$30.57	$29.07	$41.31	$42.53	$62.42	$48.12	$52.17
	North	$30.11	$28.51	$40.60	$41.69	$61.20	$46.72	$50.59
	West	$28.07	$26.48	$37.06	$38.19	$55.26	$42.83	$43.48

Table 2-A-5. Regional Distribution of Off-Peak LBMP Prices ($/MWh) for Summer Capabilities Period 2001-2007.

Region	Zone	2001	2002	2003	2004	2005	2006	2007
New York City	Long Island	$36.54	$42.76	$50.51	$56.06	$94.01	$70.84	$66.81
	NYC	$34.32	$41.40	$49.96	$50.18	$82.57	$56.45	$58.36
NY East	Capital	$31.17	$33.01	$40.44	$42.93	$70.62	$48.44	$53.25
	Dunwoodie	$32.08	$33.13	$41.17	$43.96	$73.89	$51.01	$56.00
	Hudson Valley	$31.93	$32.95	$40.93	$43.14	$71.42	$50.32	$55.31
	Millwood	$31.46	$32.70	$40.56	$43.42	$73.26	$50.76	$55.87
NY West	Central	$28.68	$27.87	$36.86	$38.61	$63.65	$44.62	$47.63
	Genesee	$27.63	$27.15	$36.36	$37.88	$61.84	$43.65	$42.45
	MH Valley	$29.70	$28.61	$38.26	$40.04	$66.28	$46.42	$49.89
	North	$29.28	$27.83	$37.59	$38.84	$65.01	$44.90	$48.40
	West	$27.38	$26.59	$34.32	$35.56	$59.11	$41.87	$40.74

Table 2-A-6. Regional Distribution of Off-Peak LBMP Prices ($/MWh) for Winter Capabilities Period 2001-2007.

Region	Zone	2001	2002	2003	2004	2005	2006	2007
New York City	Long Island	$40.49	$36.05	$55.70	$53.67	$78.06	$76.18	$77.67
	NYC	$36.50	$34.40	$53.69	$52.54	$70.48	$58.99	$66.92
NY East	Capital	$34.27	$31.44	$47.34	$47.09	$62.51	$56.02	$65.92
	Dunwoodie	$34.11	$31.68	$47.23	$47.47	$63.78	$56.71	$65.36
	Hudson Valley	$34.14	$31.76	$47.19	$46.90	$62.58	$56.12	$64.84
	Millwood	$33.75	$31.30	$46.74	$46.93	$63.03	$56.49	$65.38
NY West	Central	$30.45	$28.54	$42.85	$43.53	$56.38	$48.25	$52.70
	Genesee	$29.33	$27.85	$42.02	$43.24	$54.99	$46.33	$48.08
	MH Valley	$31.45	$29.54	$44.41	$45.13	$58.46	$49.83	$54.48
	North	$30.95	$29.20	$43.65	$44.65	$57.29	$48.54	$52.80
	West	$28.76	$26.37	$39.84	$40.93	$51.32	$43.80	$46.25

Appendix 2-A-2. Binding constraints

The binding constraints for the equations for calculating revenues from various energy markets can be expressed as

- $\mathrm{N_{Energy}} * \mathrm{Q_{Energy}} \leq 0.8 * \mathrm{N_{Max}} * \mathrm{Q_{Max}}$

  i.e., the total energy delivered is less than or equal to 80% of the rated maximum energy capacity of the EES.

- $0.5 \leq \eta \leq 0.9$ i.e., the round-trip efficiencies of the EES devices considered are in the range of 0.5 to 0.9.

- $0 \leq \mathrm{N_{Energy}} \leq \mathrm{N_{Max}} \leq \left(24 * \eta / (1+\eta)\right)$ or $0 \leq \mathrm{N_{DSR}} \leq \mathrm{N_{Max}} \leq \left(24 * \eta / (1+\eta)\right)$

  The maximum duration for energy arbitrage or DSR participation is limited by the lower of the rated maximum discharge duration or $\left(24 * \eta / (1+\eta)\right)$, where η is the efficiency of EES. For example, the. maximum duration for an EES with an efficiency of 1 would be 24/2 = 12 hours, i.e., 12 hours to charge and 12 hours to discharge.

- $0 \leq N_{regulation} \leq (24 - (\eta + 1/\eta) * N_{Energy})$

  The maximum duration for providing regulation is calculated by subtracting the number of hours required for energy arbitrage (both charge and discharge) from 24 hours. For flywheels, since regulation is the only service provided, it can be utilized for all 24 hours.

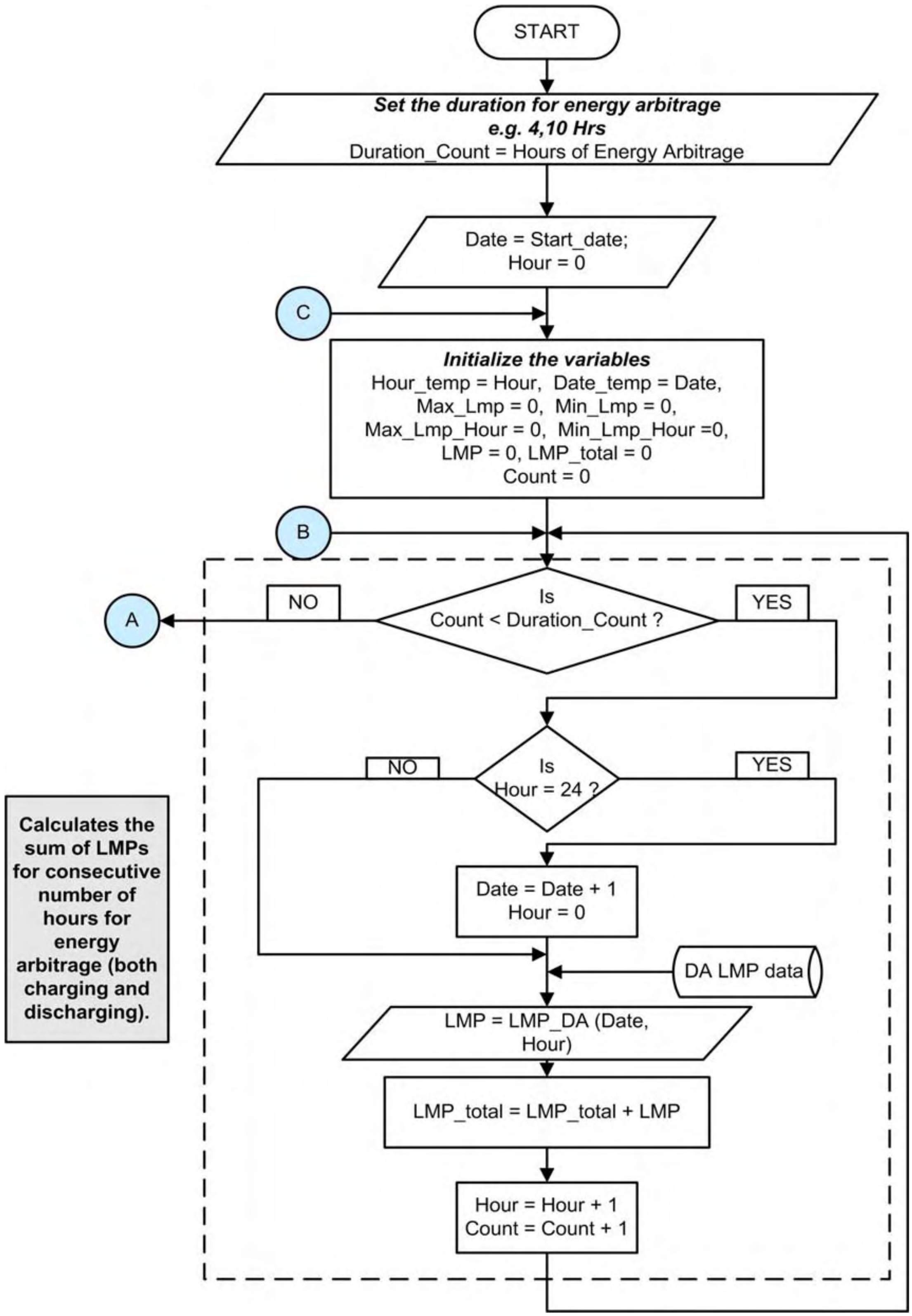
- $0 \leq \left(N_{Spinning}\ Or\ N_{NonSpin}\ Or\ N_{30\min Operating}\right) \leq N_{Max} \leq \left(24 - (\eta + 1/\eta) * \left(N_{Energy}\right) - N_{regulation}\right)$

  Similarly, a market participant can utilize the remaining capacity of the EES for providing remaining ancillary services, depending on its technical capability and the market rules.

Appendix 2-A-3. Determining the operating hours for energy arbitrage

A statistical analysis of the energy price data from 2001-04 was performed to determine the net revenue potential for 3 different operating conditions (2 Hour, 4 Hour and 10 Hour). For determining the net revenues, the maximum potential revenue period and minimum potential cost period for each day in the 3 regions were analyzed.

Figure 2-A-1 shows the flowchart explaining the methodology used to determine the operating hours for energy arbitrage i.e. least cost charging hours and maximum revenue hours for discharging the EES during summer and winter capability period. Figures 2-A-2 and 2-A-3 show distribution of 4 hour maximum revenue period during winter and summer capability months during 2001-2004. Figures 2-A-4 and 2-A-5 show distribution of 4 hour minimum revenue period during winter and summer capability months during 2001-2004. Please note that the period is specified by the 1st hour of the starting period. i.e. for a 4 hour operation, Max Hour 16 indicates, the period from 4 PM - 8 PM had maximum revenue potential for a 4 hour energy arbitrage.



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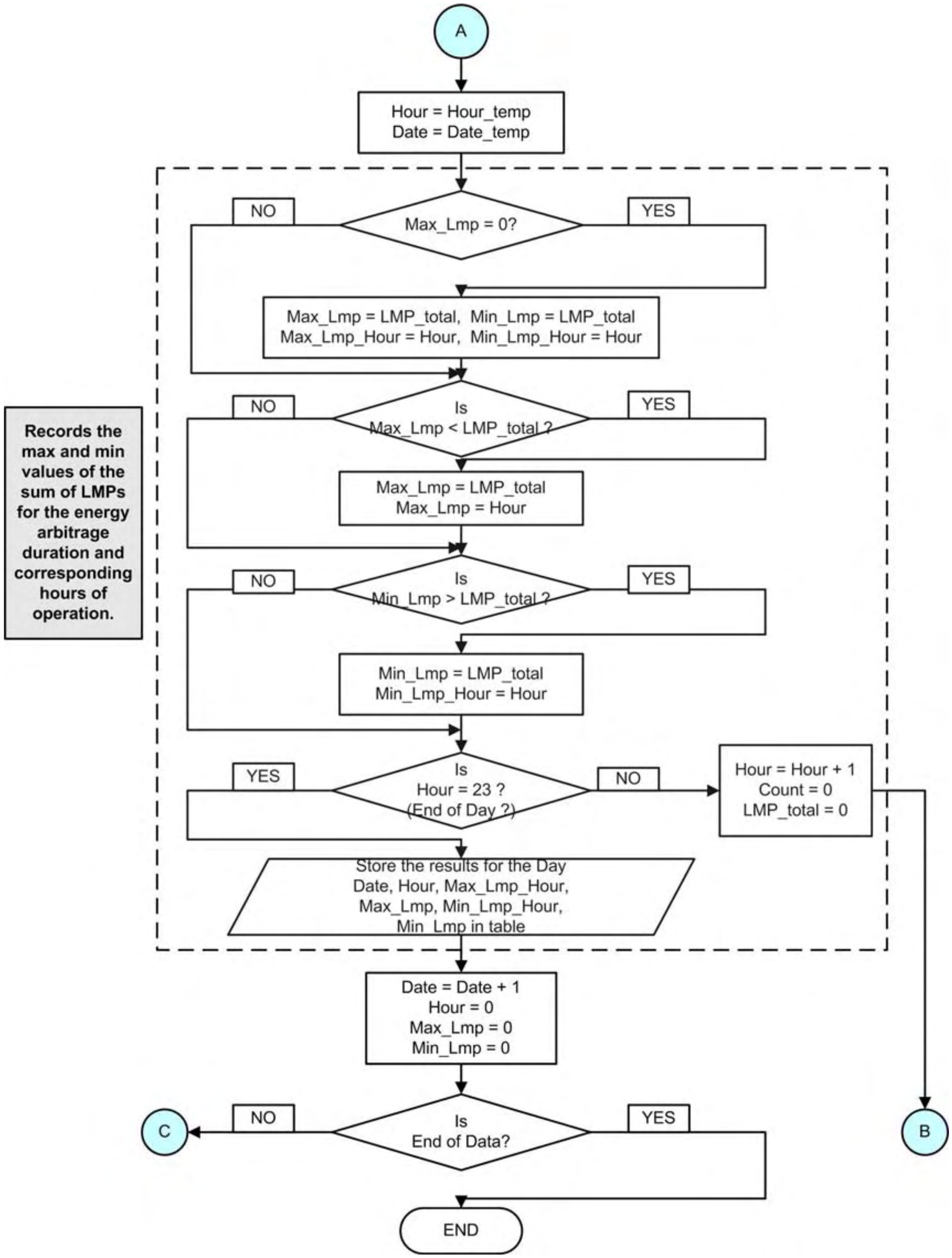


Figure 2-A-1. Flowchart explaining methodology used for determining the operating hours for energy arbitrage

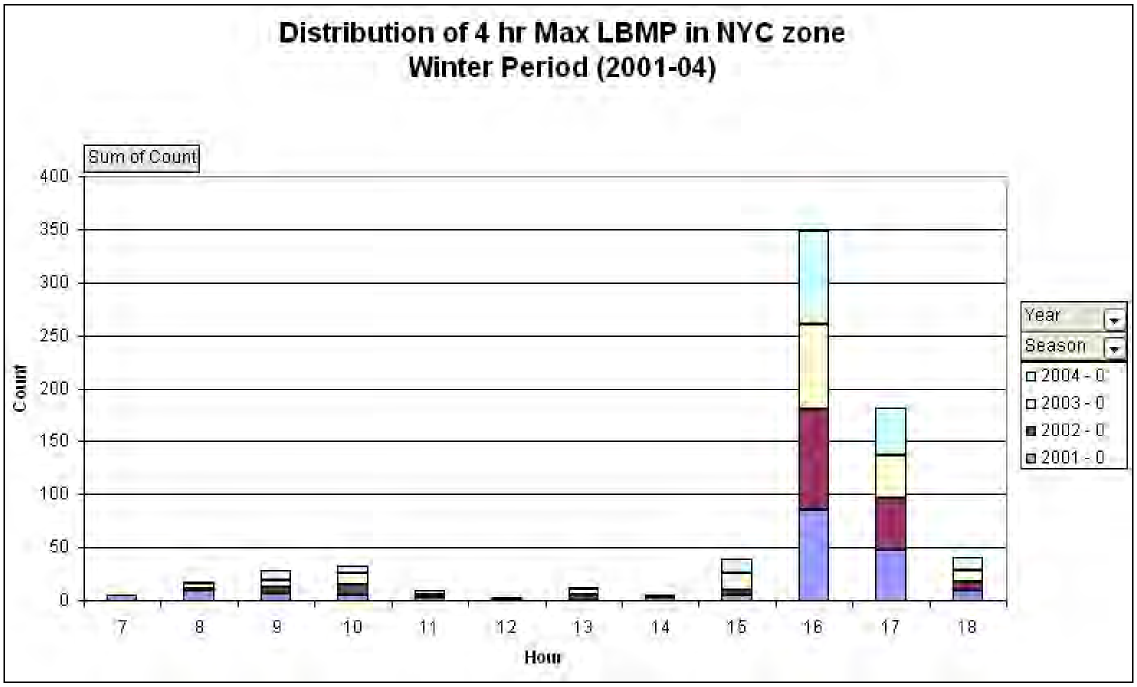


Figure 2-A-2. Distribution of 4 hour maximum LBMP in NYC Zone 2001-04 – Winter Period.

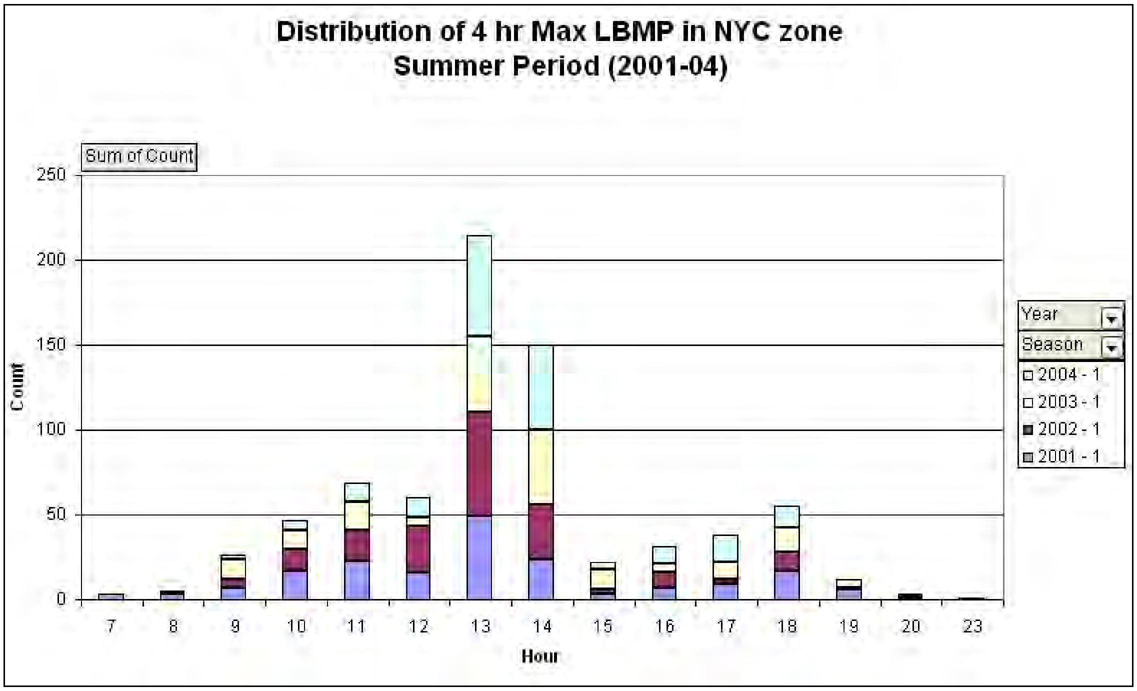


Figure 2-A-3. Distribution of 4 hour Maximum LBMP in NYC Zone 2001-04 – Summer Period.

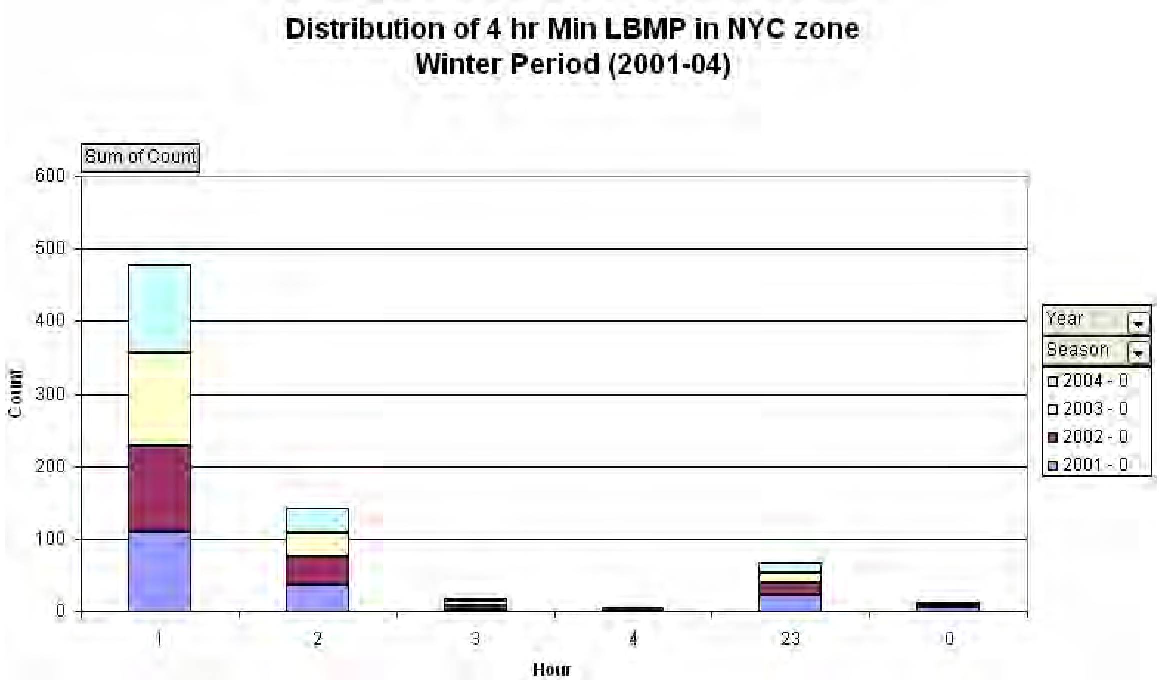


Figure 2-A-4: Distribution of 4 hour Minimum LBMP in NYC Zone Winter 2001-04.

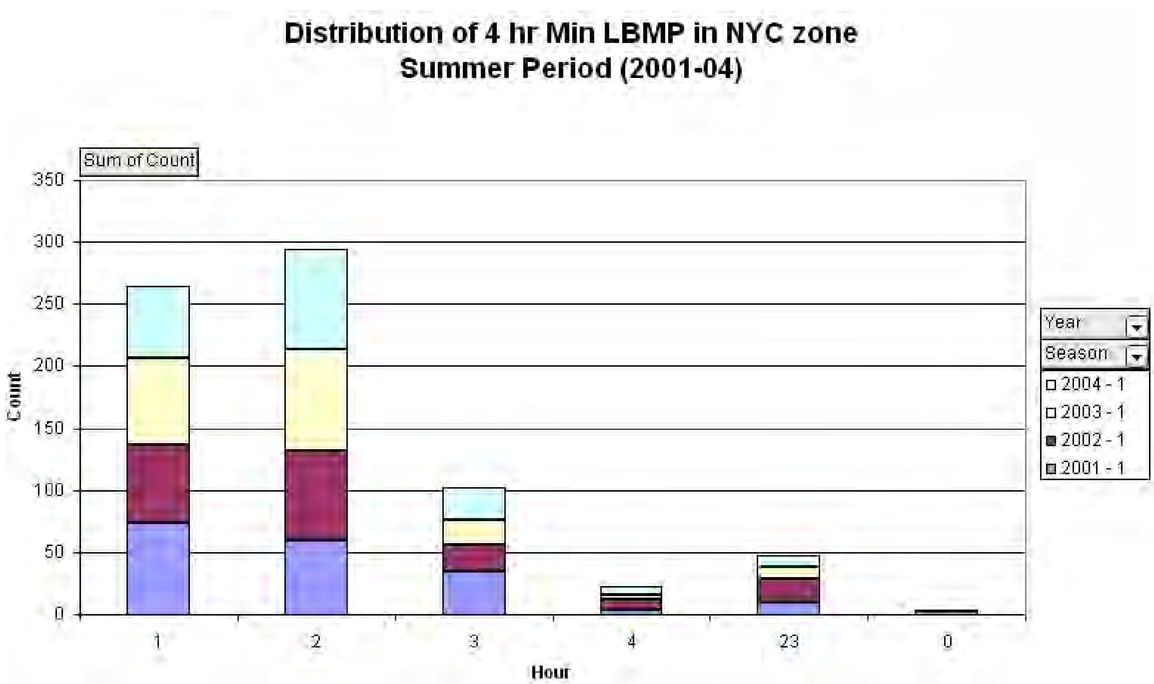


Figure 2-A-5: Distribution of 4 hour Minimum LBMP in NYC Zone Summer 2001-04.

Appendix 2-A-4. Estimating emission impact due to EES integration in NYC

Since NYC has the maximum revenue potential for energy arbitrage amongst all the regions analyzed in this research, I conducted scenario analysis to determine emission impact from large scale integration of EES for energy arbitrage in NYC region. I have assumed up to 500MW of NaS battery installation in NYC region and have attempted to assess the impact of using these batteries for 4 hour energy arbitrage during peak summer months (July - August). Based on the LMPs across various NYISO zones and the load profiles shown in Figure 2-A-9, I determined that there is sufficient transmission capacity available during off peak hours when the EES units will be charged. This allows the EES to be charged using lowest cost generating units available during off peak hours. The actual generating unit used will depend on the load during off peak hours and the marginal cost of various generators that determines the dispatch order. Since the marginal cost for generators are not available, I estimated the marginal cost for NYISO based generating units based on heat rate data available in the National Electric Energy Data System (NEEDS) database (EPA, 2006) and fuel prices for NY (EIA, 2007). The fuel price assumptions used for this analysis are summarized in Table 2-A-7.

The marginal fuel cost for individual units was then used to create the short run marginal cost (SRMC) curve as a proxy for economic unit dispatch for NYISO during unconstrained charging hours (1 am to 5 am). The NEEDS database shows that there are a number of generating units in NY, which can be run on both natural gas and oil (RFO / DFO). Thus I created 2 separate SRMC curves assuming that these units were using either natural gas or oil as the fuel source. Figure 2-A-6 shows the resulting SRMC curve when the combined fuel units in NY were modeled to use natural gas as the fuel source.

Table 2-A-7: Assumed fuel prices and variable costs (EIA, 2007)

Fuel	Fuel Price
Residual Fuel Oil (RFO)	9.40 $/MMBTU
Distillate Fuel Oil (DFO)	15.23 $/MMBTU
Coal	2.44 $/MMBTU
Natural Gas	7.63 $/MMBTU
Nuclear	18.00 $/MWh
Wind	20.00 $/MWh
Hydro	10.00 $/MWh

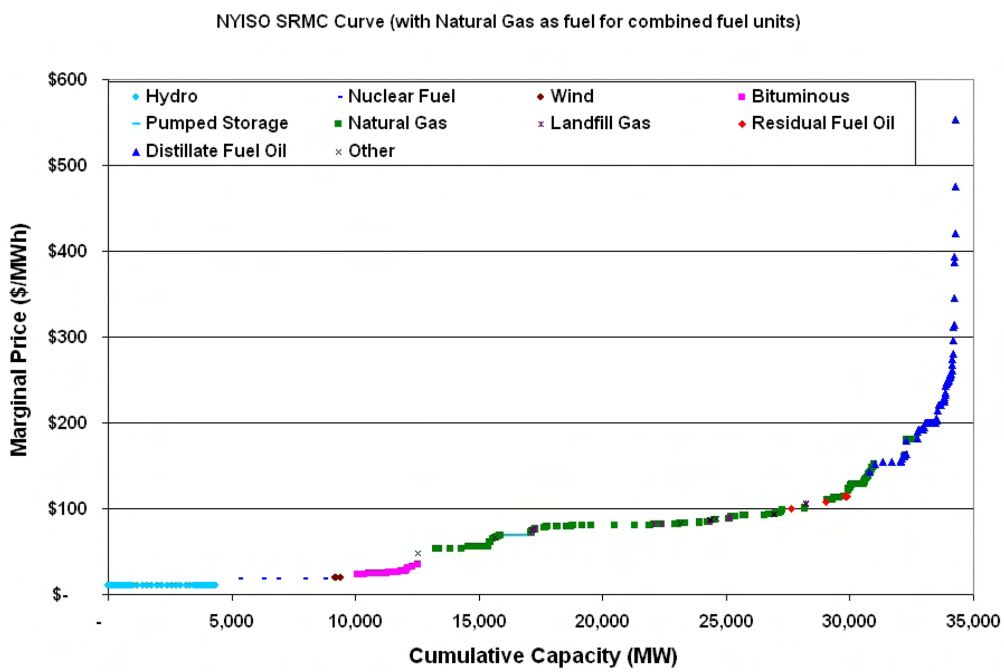


Figure 2-A-6. Short run marginal cost (SRMC) curve for NYISO generating units assuming natural gas as the fuel source for combined fuel units.

Figure 2-A-7 shows the resulting SRMC curve when the combined fuel units in NY were modeled to use RFO / DFO as the fuel source. The choice of fuel changes the marginal cost of the duel fuel capable units and thus can change the marginal unit used for charging the EES unit at night.

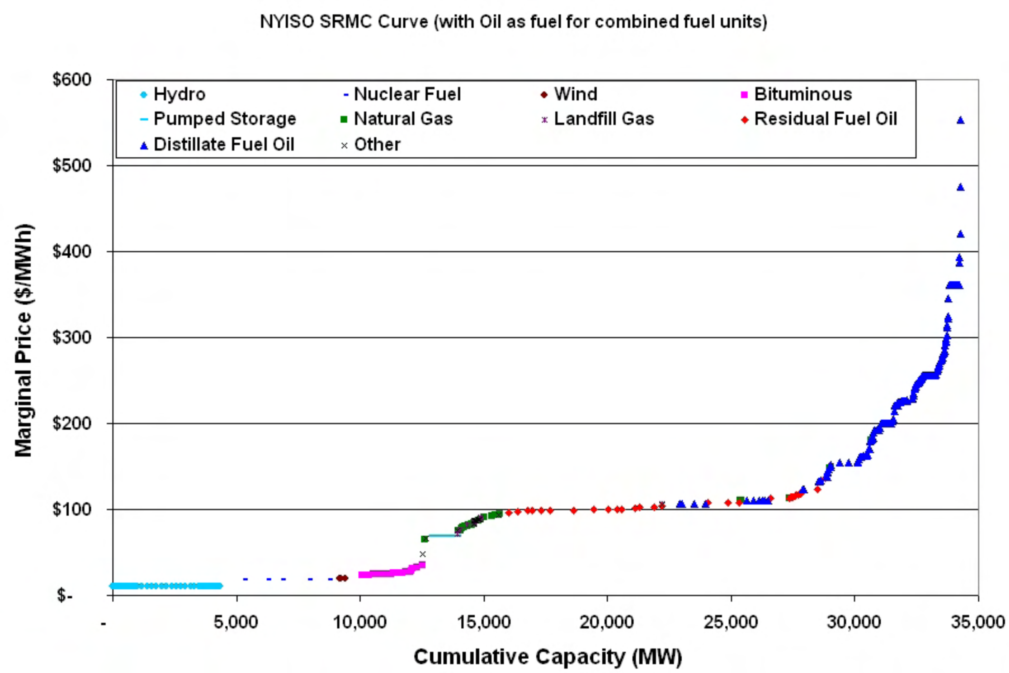
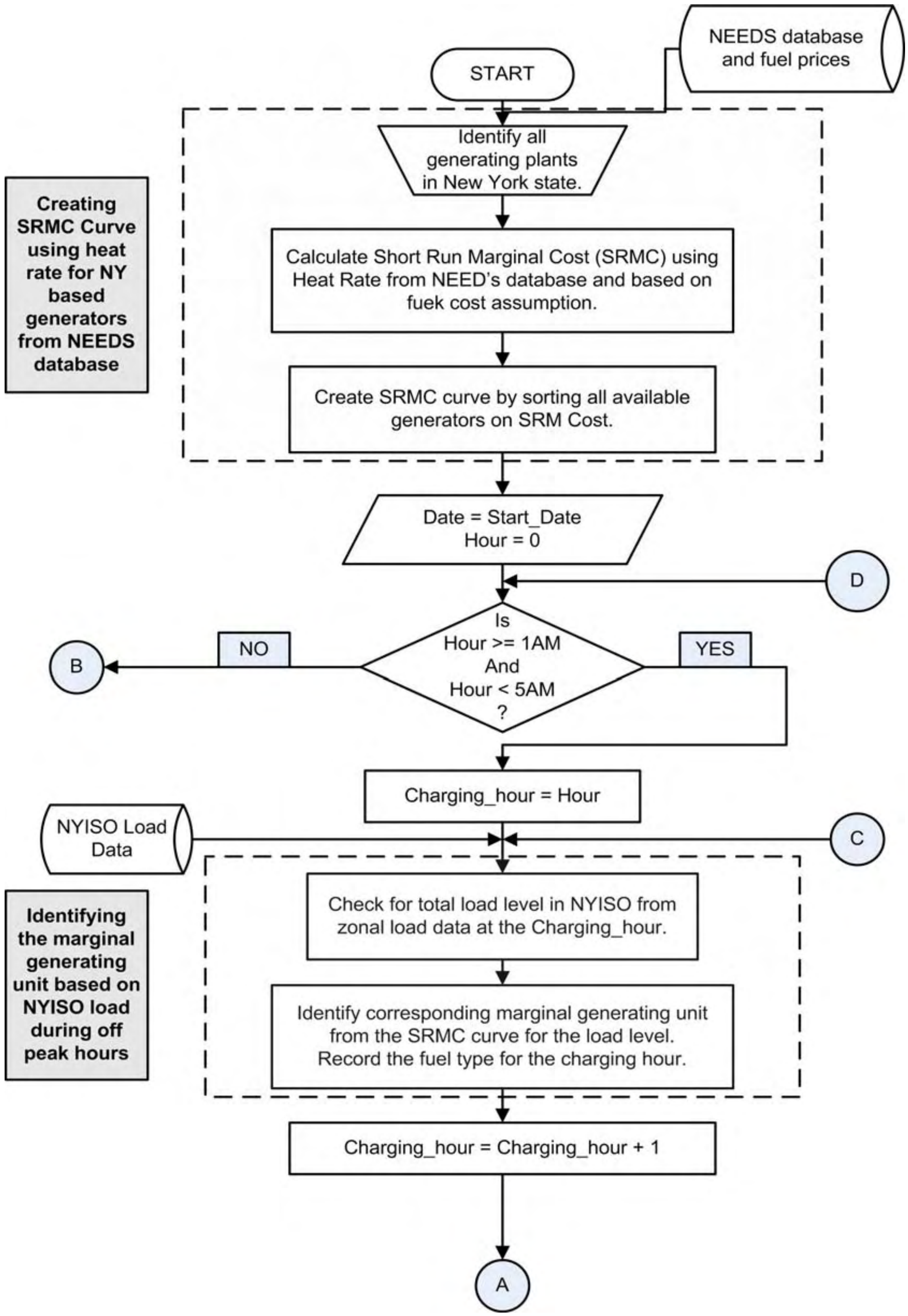


Figure 2-A-7. Short run marginal cost (SRMC) curve for NYISO generating units assuming oil as the fuel source for combined fuel units.

Figure 2-A-8 is a flowchart that explains the methodology used for determining weighing factors for the marginal fuel type by keeping track of marginal units and fuel source. By mapping the daily load profile (Figure 2-A-9) for NYISO (NYISO 2007, c) with the SRMC curve, I estimated the potentially affected plants during charging cycles. Due to variations in the daily load levels, the marginal plant during charging cycle can be different on different days.



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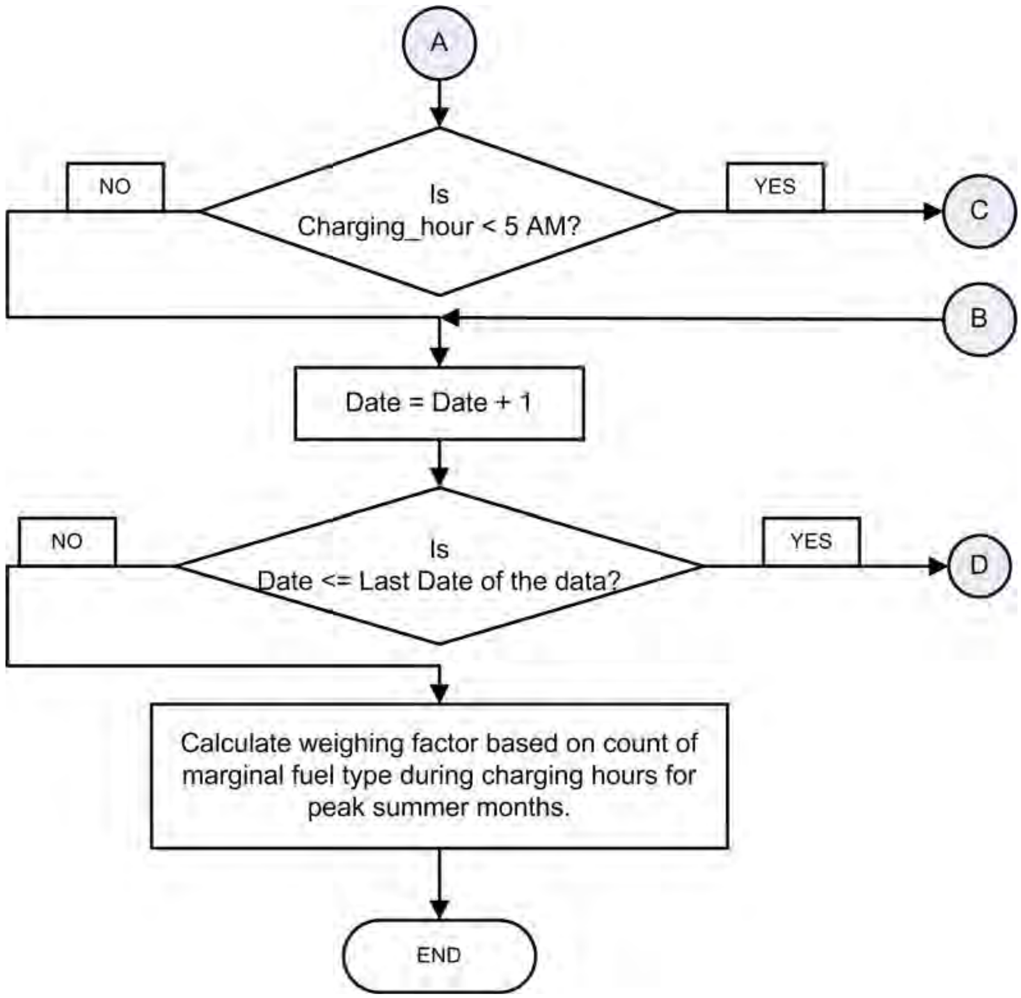


Figure 2-A-8. Flowchart explaining the methodology used to determine the weighing factor for marginal fuel for plants displaced by EES during charging hours.

The result of this analysis is shown in Figure 2-A-10. When the dual fuel capable units in NY use natural gas as the fuel (case 1), the marginal fuel for over 97% of hours is natural gas during the charging cycle. When the marginal fuels use oil as the fuel source (case 2), the marginal fuel for charging is RFO for almost 52% of the hours followed by natural gas for almost 46% of the hours.

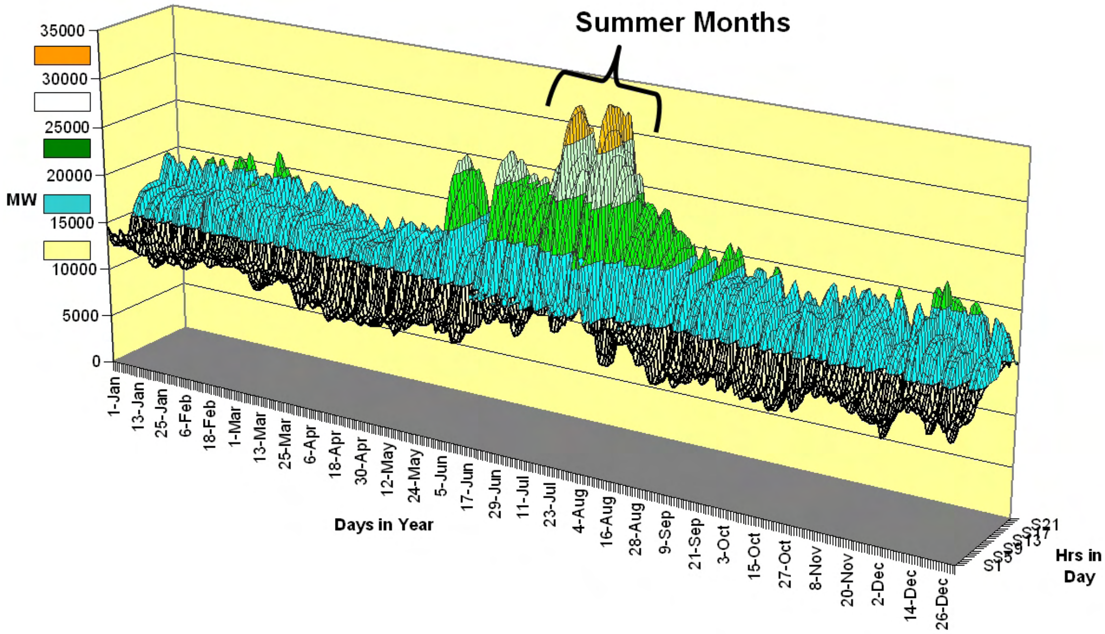


Figure 2-A-9. Daily load profile curves for NYISO for 2006.

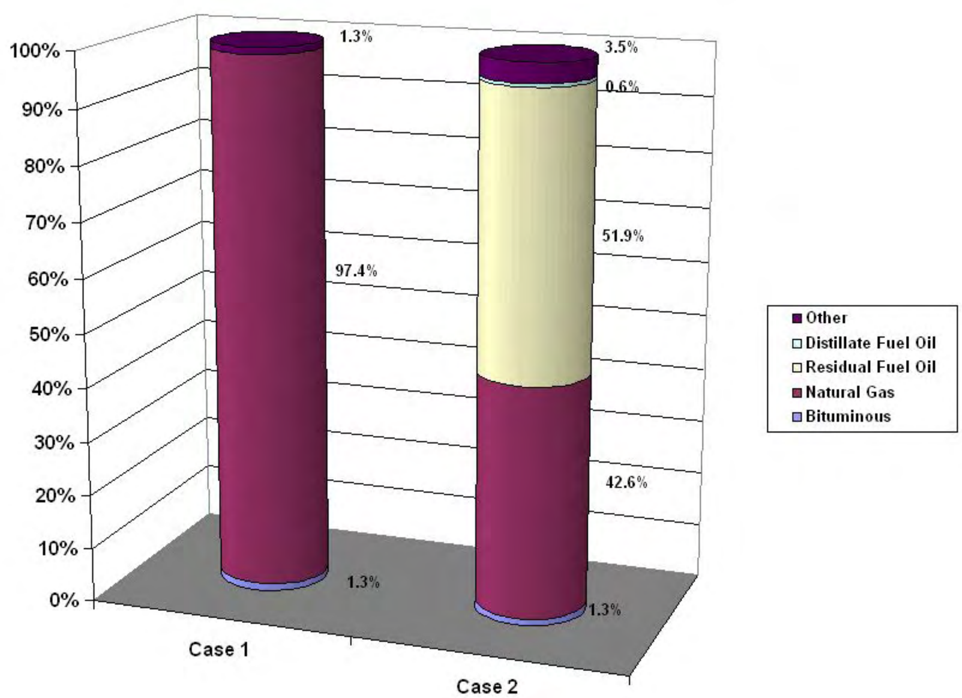


Figure 2-A-10. Weighing factor for the marginal fuel type used by the generating units used for charging the EES during July – August.

The weighing factors for off peak marginal fuel are used by my colleague, Elisabeth Gilmore for analyzing the emission impact due to EES by using emission profiles from 5 potentially affected plants. These plants and their location is shown in Figure 2-A-11. The 3 potential units used as charging units are C.R. Huntley (a coal based plant) in NY West, Roseton (RFO based plant) and Athens (natural gas based plant) located in NY East.

Since NYC has limited transmission availability and the transmission systems are constrained during the peak hours of summer, NYC based plants are the potential units displaced by EES operation during summer. Due to transmission constraints during the peak days in summer, it is not appropriate to use a system marginal cost curve to determine the marginal unit during peak hours. The 2 units being used by Elisabeth Gilmore for emission analysis (Figure 2-A-10) are Astoria (RFO) and Gowanus (natural gas), both located in NYC.

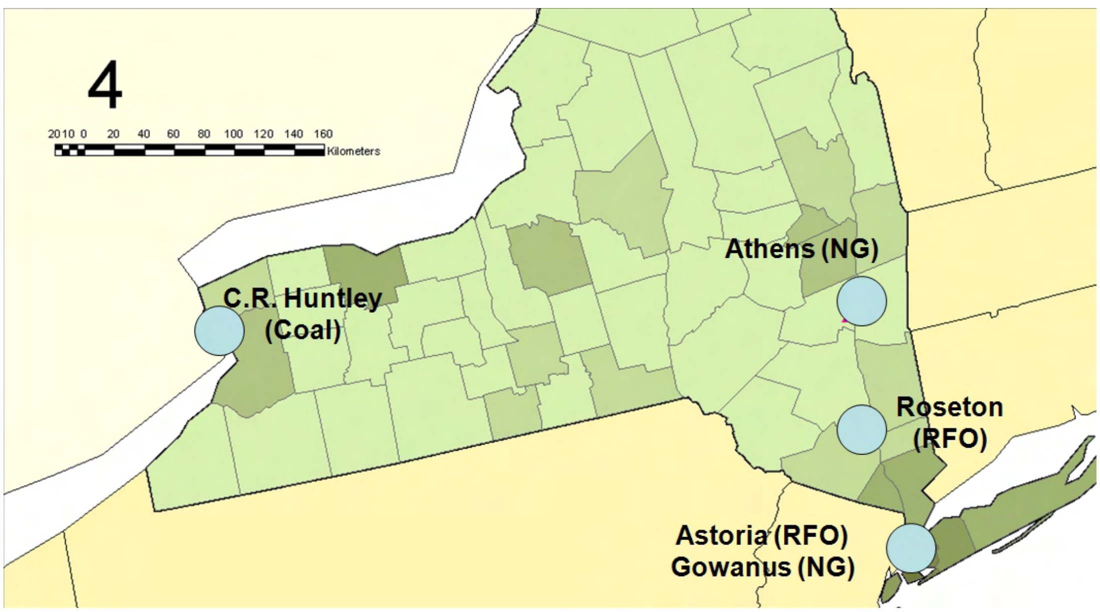


Figure 2-A-11. Potential generating units affected by EES operation in NYC.

Appendix 2-A-5. Sensitivity analysis for financial input parameters of NPV for NaS batteries for energy arbitrage

I performed a sensitivity analysis to determine the most important factors influencing the economics of NaS batteries for energy arbitrage in NYC. Table 2-A-8 summarizes the range of input parameters used for the sensitivity analysis.

Table 2-A-8: Range for financial parameters used for sensitivity analysis.

Input Variable	Low	Base	High
T&D Benefits ($/kW-Year)	$-	$150	$300
Capital Cost ($/kW)	$1,500	$2,000	$3,000
Annual Revenues ($/MW)	$150,000	$250,000	$350,000
Charging Cost ($/MW)	$40,000	$60,000	$90,000
O&M Costs ($/kW-Year)	$20	$30	$50
Efficiency	65%	75%	85%
Discount Factor	5%	10%	15%

The base case had a NPV of -$225,000. Figure 2-A-12 shows the results of the sensitivity analysis as a tornado plot. Each bar indicates the variability in the NPV as a result of changing an individual factor. For example, the NPV will increase from -$225,000 to $700,000 if the installation can be used at a location which offers T&D benefits of $300 / kW-Year. Also the NPV will increase to $275,000 as compared to the base case if the capital cost is reduced to $1,500 /kW from the base case assumption of $2,000/kW.

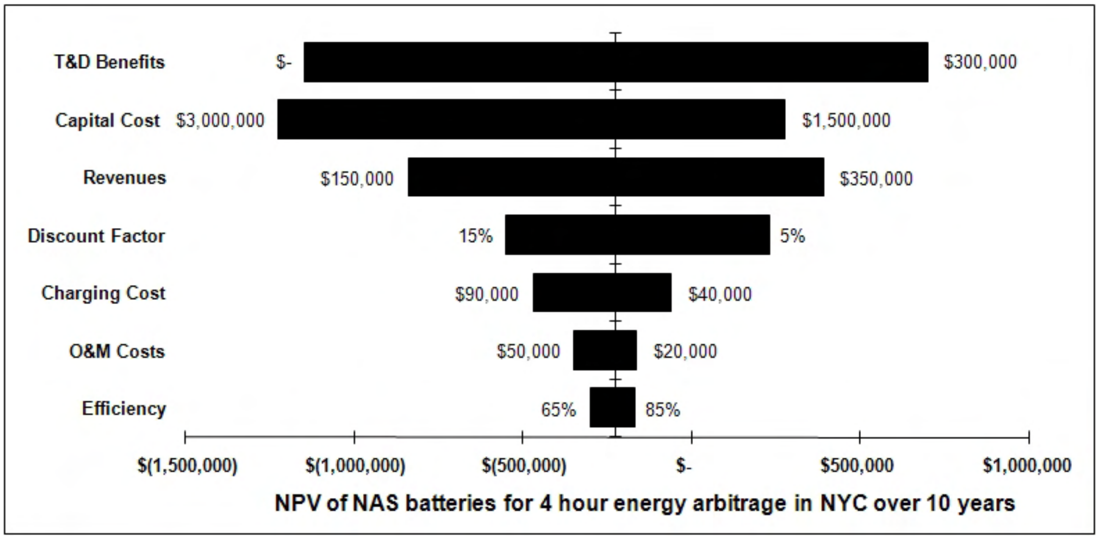


Figure 2-A-12. Sensitivity analysis for the net present value (NPV) of NaS installation for 4 hours energy arbitrage in NYC.

Chapter 3: Economics of EES in PJM

3-1. Introduction: PJM electricity markets and EES

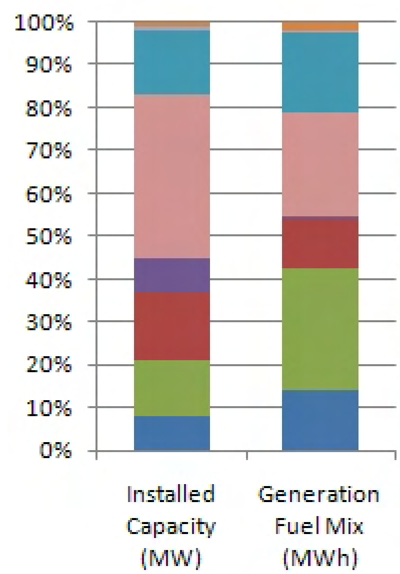
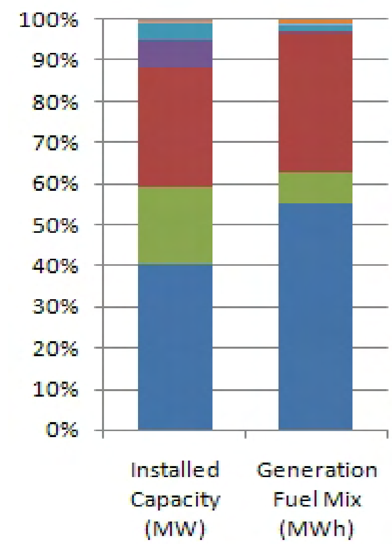
As NYISO does, the PJM Interconnection offers opportunities for electric energy storage (EES) to participate in wholesale electricity markets. In this chapter, I have quantified various revenue streams available to EES through PJM markets and compared the net present value of NaS batteries and flywheels for various applications.

The PJM Interconnection serves over 50 million people in the United States, serving a peak load of 145,000 MW with 165,000 MW of generation, making it the world's largest electricity market.

PJM's markets cover all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. (PJM, 2008a) PJM operates a Locational Marginal Price (LMP) based day-ahead and real-time energy market, a capacity market (using the Reliability Pricing Model), and ancillary service markets (regulation and synchronized reserve markets).

Table 3-1 provides a summary comparison of the PJM market with the NYISO market covered in Chapter 2. Figure 3-1 shows the geographical area covered by the PJM Interconnection and the locations of 17 zones within PJM. The 17 PJM zones are listed in Table 3-2. PJM underwent significant expansion during 2002-2005, so I have used the market results from 2005-2007 for evaluating the economics of EES in PJM markets to avoid drawing conclusions from transitional market behavior during the PJM expansion.

Table 3-1: Summary comparison of NYISO and PJM markets [5]

	NYISO	PJM
Established in	**1999**	**1997**
Population Served	19 Million	51 Million
States (All or parts of)	NY	DE, IL, IN, KY, MD, MI, NC, NJ, OH, PA, TN, VA, WV and DC
Generation Units	235+	1,270+
Transmission (Miles)	10,775	56,250
Peak Load (Pre 2006)	33.9 GW (32.1 GW)	144.6 GW (133.8 GW)
Generation Capacity	39.7 GW	164.6 GW
Capacity Reserves	5.8 GW (14.8%)	20.0 GW (12.2%)
2006 Average Real Time Energy Price	$70.9/MWh - $86.15/MWh	$50.07/ MWh
Generation Mix Other Wind Hydro Gas & Oil Oil Natural Gas Nuclear Coal		
Marginal Fuel	Natural Gas	Natural gas, Coal
Markets	• Energy: (Day Ahead, Hour Ahead, Real Time) • Capacity • Ancillary: ➢ Regulation ➢ Synchronized reserve ➢ Non Synch Reserve ➢ Operating Reserve	• Energy: (Day Ahead, Real Time) • Capacity • Ancillary: ➢ Regulation ➢ Synchronized reserve

[5] This summary was created based on data compiled from following sources: PJM 2008a, NYISO 2007, FERC 2007.

Table 3-2: PJM zones

1. AECO	Atlantic Electric Co
2. AEP	American Electric Power Co *(joined PJM in May 2004)*
3. APS	Allegheny Power Systems (*joined PJM in Apr 2002)*
4. BGE	Baltimore Gas & Electric
5. COMED	Commonwealth Edison *(joined PJM in May 2004)*
6. DAY	Dayton Power and Light *(joined PJM in May 2004)*
7. DOM	Dominion *(joined PJM in May 2005)*
8. DPL	Delmarva Power & Light
9. DUQ	Duquesne Light *(joined PJM in Jan 2005)*
10. JCPL	Jersey Central Power & Light
11. METED	Metropolitan Edison Co
12. PECO	PECO Energy
13. PENELEC	Pennsylvania Electric Co
14. PEPCO	Potomac Electric Power Co
15. PPL	PPL Electric Utilities
16. PSEG	Public Service Electric & Gas Co
17. RECO	Rockland Electric Co *(joined PJM in March 2002)*

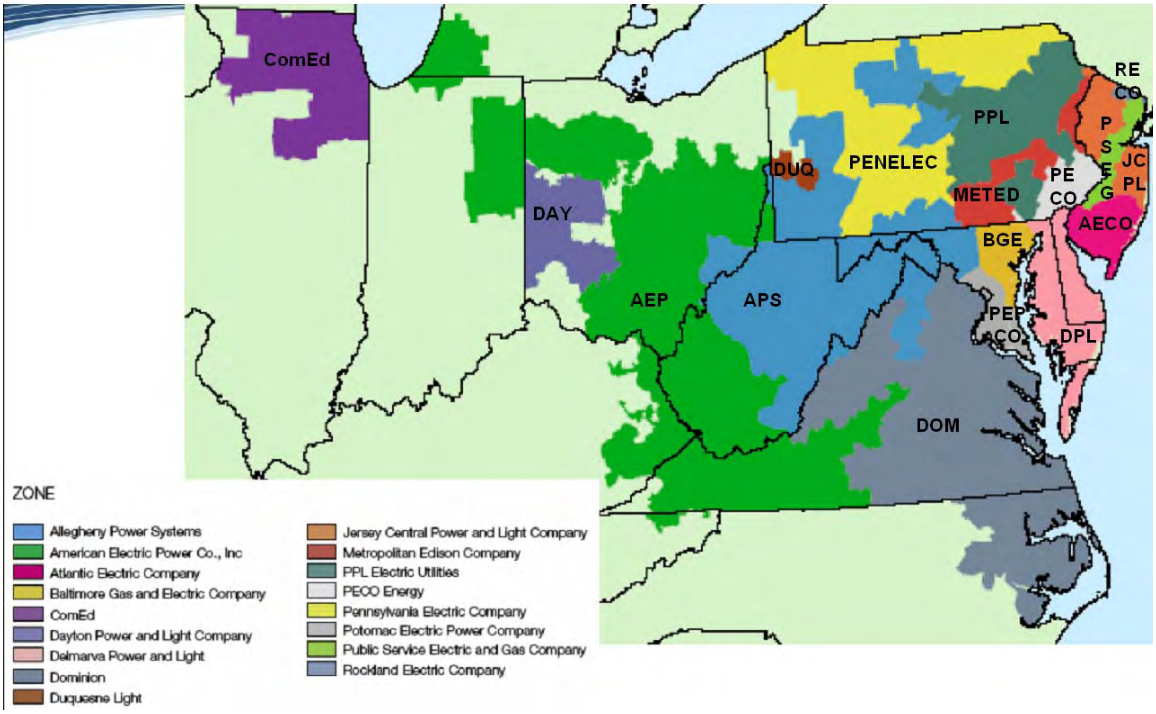


Figure 3-1: PJM footprint and zonal map (Source: PJM 2007a)

3-2. Quantifying revenue potential for EES in PJM markets

I have grouped these 17 zones into 4 super-zones based on a statistical analysis of energy market results (PJM 2008b), geographical considerations, and transmission constraints. Table 3-3 shows the results of the correlation analysis performed using hourly zonal energy prices for all 17 zones during 2006. The zones were grouped into super-zones based on a correlation coefficient of 0.98 or higher. The 4 super-zones are color coded to show the grouping used for further analysis.

The super-zones are listed below:

- **PJM Central**: PENELEC and APS
- **PJM South**: BGE, PEPCO, and DOM
- **PJM West**: COMED, AEP, DAY, and DUQ
- **PJM East**: AECO, DPL, JCPL, METED, PECO, PPL, PSEG, and RECO

Table 3-3: Results of the correlation analysis to determine super-zones for PJM

	PEN ELEC	APS	BGE	PEP CO	DOM	COM ED	AEP	DAY	DUQ	AE CO	DPL	JCPL	MET ED	PECO	PPL	PS EG	RE CO
PENELEC	1.00																
APS	0.98	1.00															
BGE	0.94	0.95	1.00														
PEPCO	0.92	0.94	1.00	1.00													
DOM	0.93	0.94	0.99	0.98	1.00												
COMED	0.95	0.93	0.85	0.82	0.85	1.00											
AEP	0.96	0.94	0.87	0.84	0.87	0.99	1.00										
DAY	0.94	0.91	0.83	0.80	0.83	0.99	0.99	1.00									
DUQ	0.93	0.90	0.81	0.79	0.81	0.97	0.98	0.98	1.00								
AECO	0.95	0.95	0.97	0.96	0.95	0.87	0.88	0.85	0.83	1.00							
DPL	0.96	0.96	0.98	0.96	0.96	0.87	0.89	0.86	0.84	0.99	1.00						
JCPL	0.96	0.96	0.97	0.96	0.95	0.89	0.90	0.87	0.85	0.98	0.99	1.00					
METED	0.96	0.97	0.98	0.97	0.96	0.87	0.89	0.86	0.84	0.98	0.99	0.99	1.00				
PECO	0.96	0.96	0.97	0.96	0.95	0.88	0.89	0.86	0.84	0.99	0.99	0.99	0.99	1.00			
PPL	0.97	0.96	0.98	0.96	0.96	0.89	0.90	0.87	0.85	0.99	0.99	1.00	0.99	0.99	1.00		
PSEG	0.97	0.96	0.97	0.95	0.95	0.89	0.91	0.88	0.86	0.98	0.99	0.99	0.98	0.99	0.99	1.00	
RECO	0.97	0.96	0.95	0.94	0.94	0.89	0.91	0.88	0.87	0.97	0.98	0.98	0.97	0.98	0.98	1.00	1.00

Tables 3-A-1 to 3-A-6 in appendix provide the details of the regional distribution of the average peak and off-peak LMPs during 2005-2007 for all 17 PJM zones.

Figure 3-2 shows the average daily LMP curves for different seasons during 2005-06 for all 17 zones in PJM. In this Figure the zones are grouped based on super groups for comparison of the daily LMP curves within each super-zone. The daily curve for each zone represents the average LMP for each hour of the day for the zone during the summer and winter of 2005 and 2006. Based on these LMP curves, PJM East and PJM South zones could have been grouped together, but I decided to use the 4 super-zones based on the correlation analysis as well as on expected capacity revenue differences (discussed later in section 3-4).

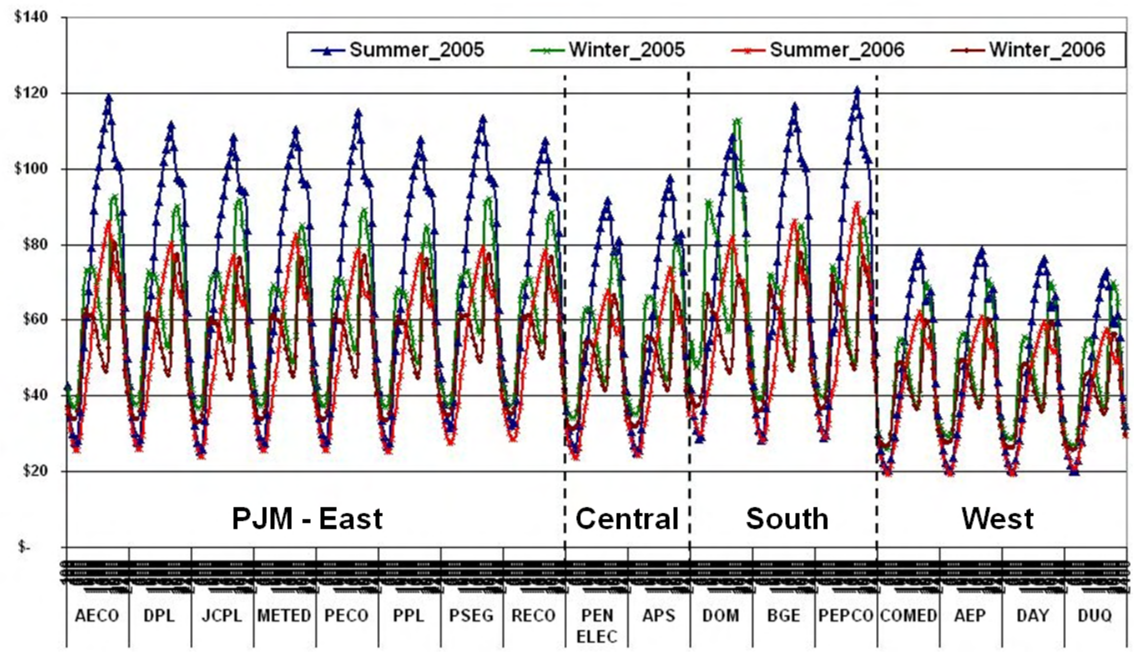


Figure 3-2: Average daily LMP curves from energy market for summer and winter 2005-2006 for all PJM zones

The grouping of the 17 PJM zones into 4 super-zones is also supported by transmission constraints as shown in Figure 3-3. Figure 3-4 shows the geographical grouping of the 4 super-zones selected for analysis. PJM East super-zone includes zones that are north and east of central interface, PJM Central super-zone includes zones that are influenced by western interface and PJM South super-zone includes zones that are located south of the central interface. PJM West super-zone includes regions dominated by area with coal plants.

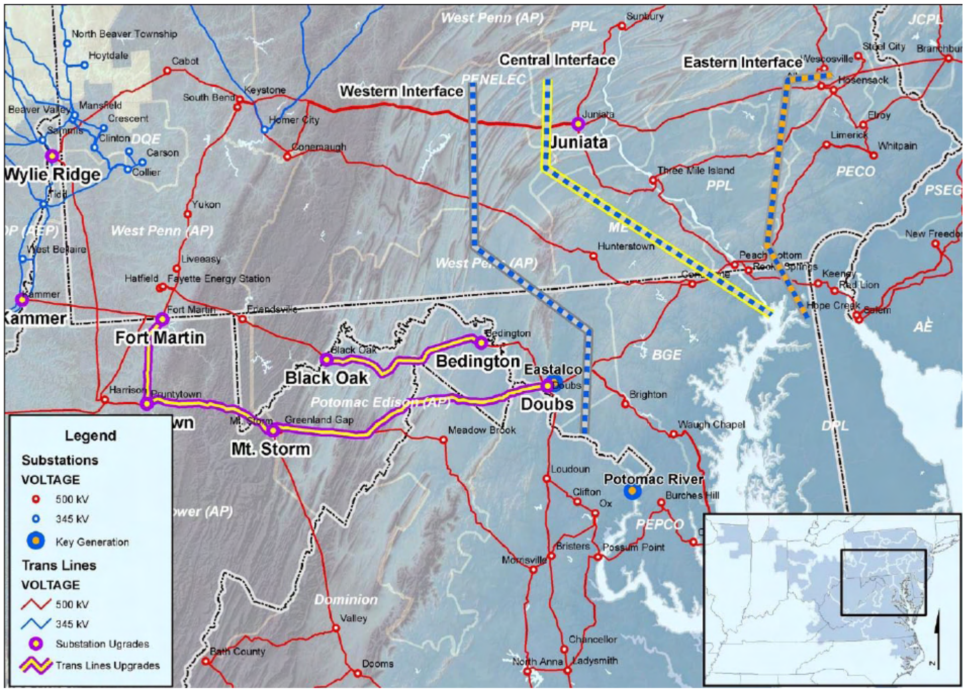


Figure 3-3: PJM Transmission interfaces (Source: PJM 2007a)

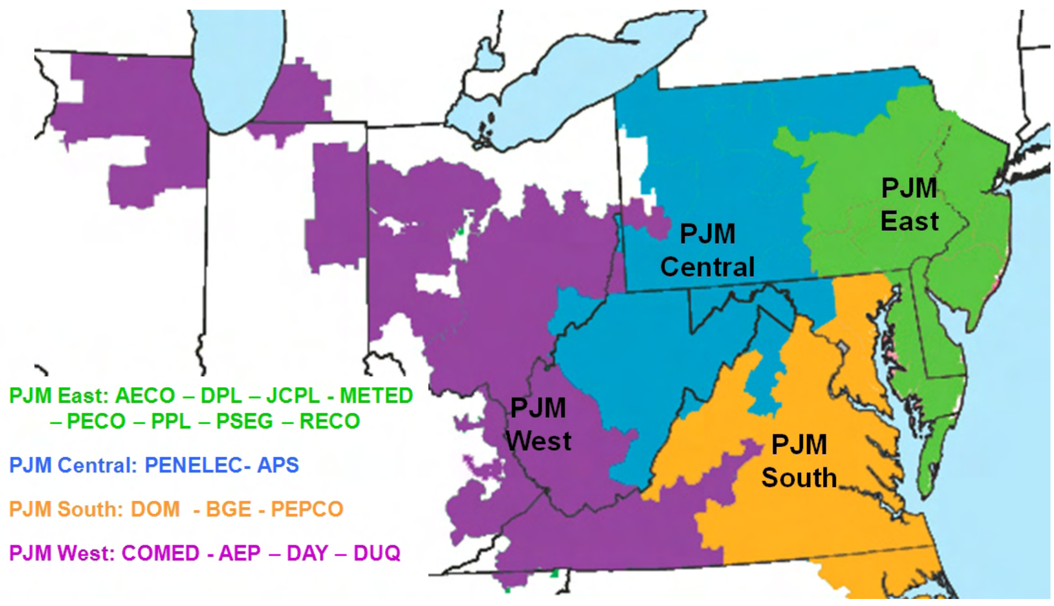


Figure 3-4: PJM super-zones

These 4 super-zones were used for identifying the various revenue streams for NaS batteries and flywheels in the PJM markets. The revenue streams available for EES in PJM include:

- Energy arbitrage through participation in day-ahead/real-time energy markets
- Capacity revenues under the Reliability Pricing Mechanism (RPM) model
- Ancillary service market revenues for providing regulation and/or synchronized reserves

Based on the technical characteristics of flywheels and NaS batteries, this research evaluated the economics of using flywheels for providing regulation and NaS batteries for providing energy arbitrage and synchronized reserves in the PJM electricity market. The analytical framework used for quantifying the revenue streams is described in section 2-4 of Chapter 2 and binding constraints are discussed in Appendix 2-A-2.

3-3. Energy arbitrage

The hourly electricity markets (day-ahead and real-time) in PJM provide opportunities for EES technologies such as NaS batteries to participate in the energy markets and capture the energy arbitrage revenue. While average hourly electricity prices in PJM's real time market ranged between \$49/MWh and \$58/MWh during 2005-2007, peak prices went above \$100/MWh for 1100, 470, and 780 hours respectively, during 2005, 2006, and 2007. Figure 3-5 shows the price duration curves for PJM's real-time energy market during 2005-2007.

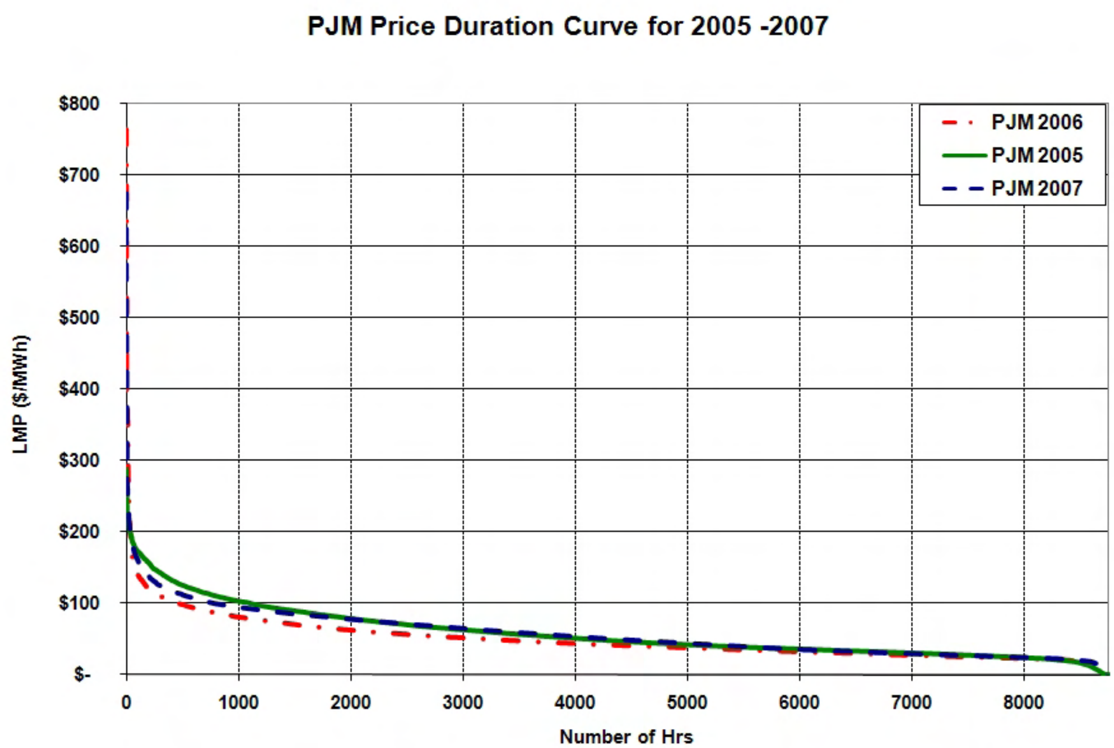


Figure 3-5: PJM real-time price duration curve for 2005-2007

3-3-1. Quantifying energy arbitrage revenue potential in PJM

For the four PJM super-zones, I have quantified the energy arbitrage revenue potential for 2-hour, 4-hour, and 10-hour discharge periods. The first step in quantifying the energy arbitrage revenue was to identify the period for maximum revenue and the period for minimum charging cost for different energy arbitrage durations. Table 3-4 summarizes the analysis performed to determine operating hours for 2-hour, 4-hour and 10-hour energy arbitrage operation by capturing the seasonal patterns for the highest-priced on-peak revenue period and the lowest-cost off-peak period. The analysis methodology is similar to one described in appendix 2-A-3.

As shown in Table 3-4, there is a clear shift in the maximum revenue period during the summer capability months (May 1 to October 31) and the winter capability months (Nov 1 to April 30). The lowest cost period does not reflect such seasonal shift. Figures 3-A-1, 3-A-2, and 3-A-3 in the Appendix show the details of results for analysis conducted to determine operating period for the 4-hour energy arbitrage.

Table 3-4: Summary of analysis for determining operating hours for energy arbitrage

	Max Revenue Period		Min Charging Cost period
	Summer	Winter	Annual
2 Hr Operation	16:00 - 17:00	18:00 - 19:00	3:00 - 4:00
4 Hr Operation	15:00 - 18:00	18:00 - 21:00	2:00 - 5:00
10 Hr Operation	12:00 - 21:00	13:00 - 22:00	23:00 - 8:00

** PJM uses the convention of hour ending with to define all operating hours*

Using these operating hours, the annual net revenues for energy arbitrage were calculated. Table 3-5 shows the summary of annual net revenues (thousand $/ MW) generated in different zones for 2-, 4-, and 10-hour energy arbitrage using 2005-2007 energy market data. These results are based on round-trip efficiency of 0.75 for the NaS battery.

Table 3-5: Summary of the annual net revenue for energy arbitrage (2005-2007)

	PJM East (PECO)			PJM South (BGE)			PJM Central (PENELC)			PJM West (AEP)		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
10 Hr	$ 59	$ 76	$ 107	$ 59	$ 72	$ 101	$ 49	$ 64	$ 80	$ 49	$ 66	$ 77
4 Hr	$ 51	$ 63	$ 80	$ 53	$ 64	$ 77	$ 42	$ 52	$ 62	$ 40	$ 50	$ 57
2 Hr	$ 28	$ 34	$ 44	$ 29	$ 35	$ 41	$ 22	$ 27	$ 33	$ 20	$ 26	$ 29

3-3-2. Effect of round-trip efficiency on energy arbitrage revenues

Since the EES technologies considered for this analysis are yet to be fully commercialized, I performed additional sensitivity analysis to determine the effect of round-trip efficiency on the net revenue potential for energy arbitrage in the four super-zones. Currently most of the manufacturers claim that their EES technologies can offer round-trip efficiencies of 70%-85%. Figures 3-6, 3-7, 3-8, and 3-9 show the result of an analysis conducted to calculate the effect of round-trip efficiency on net revenues (i.e., the difference between on- peak revenues and off-peak charging costs) from energy arbitrage during 2005-2007.

Lower round-trip efficiencies result in higher charging costs due to additional charging time required to cover the losses. These results show a switchover point at around 73% round-trip efficiency where the 4-hour arbitrage results in higher net revenues than the 10-hour energy arbitrage operations for three of the four super-zones (PJM East, PJM Central, and PJM South). This analysis indicates that if the EES unit had round-trip efficiency less than 73%, the market participant operating in the PJM East, Central, or South region would have earned higher net revenues by operating the unit for four hours than its net revenues for 10 hours of operation during 2005-2007. For PJM West this switchover point occurs at 69% round-trip efficiency and for a round trip efficiency of approximately 60%, even 2 hour energy arbitrage would have resulted in higher net revenues than 10 hour operation. This switchover point between 2 hour and 10 hour operation occurs at a round trip efficiency of ~ 65% for PJM East, Central and South regions.

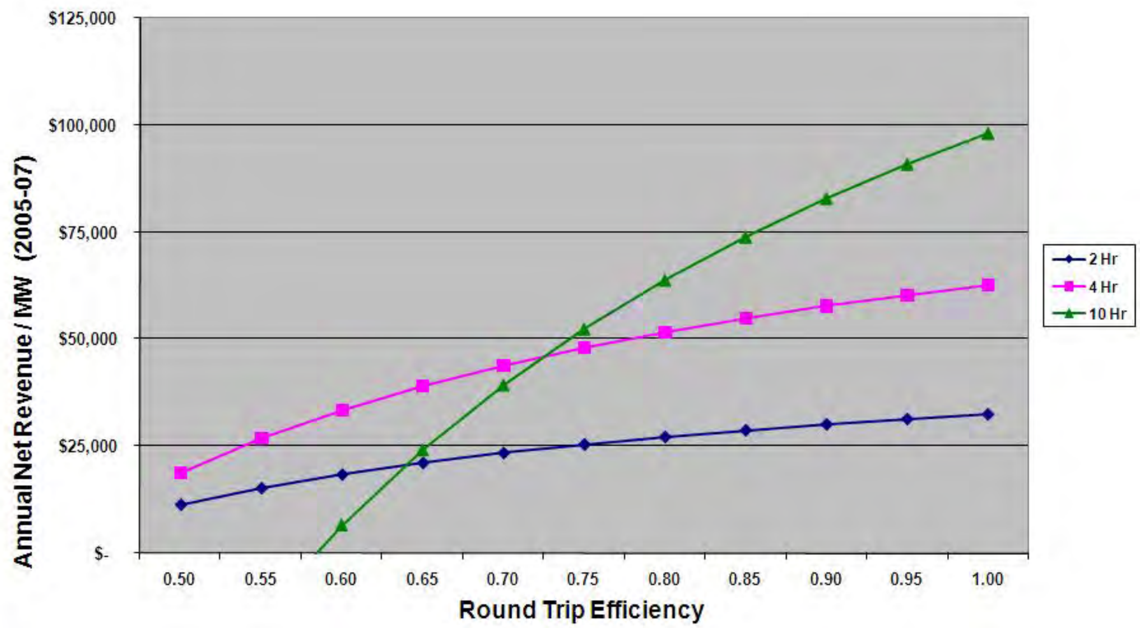


Figure 3-6: Effect of round-trip efficiency on annual net revenues from energy arbitrage for PJM Central (PENELEC)

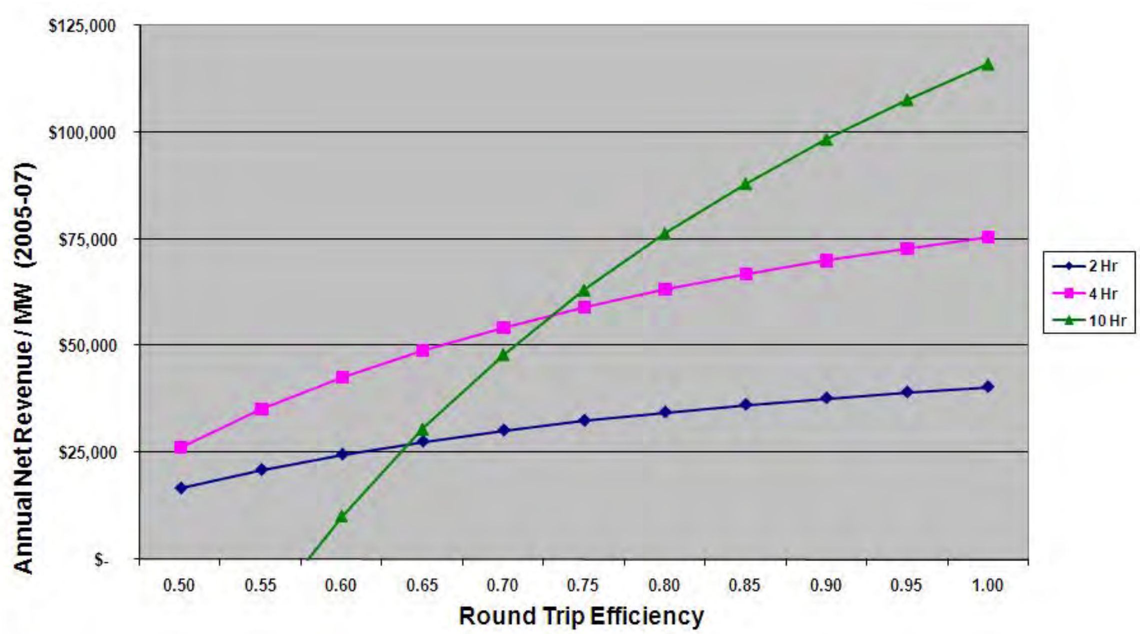


Figure 3-7: Effect of round-trip efficiency on annual net revenues from energy arbitrage for PJM East (PECO)

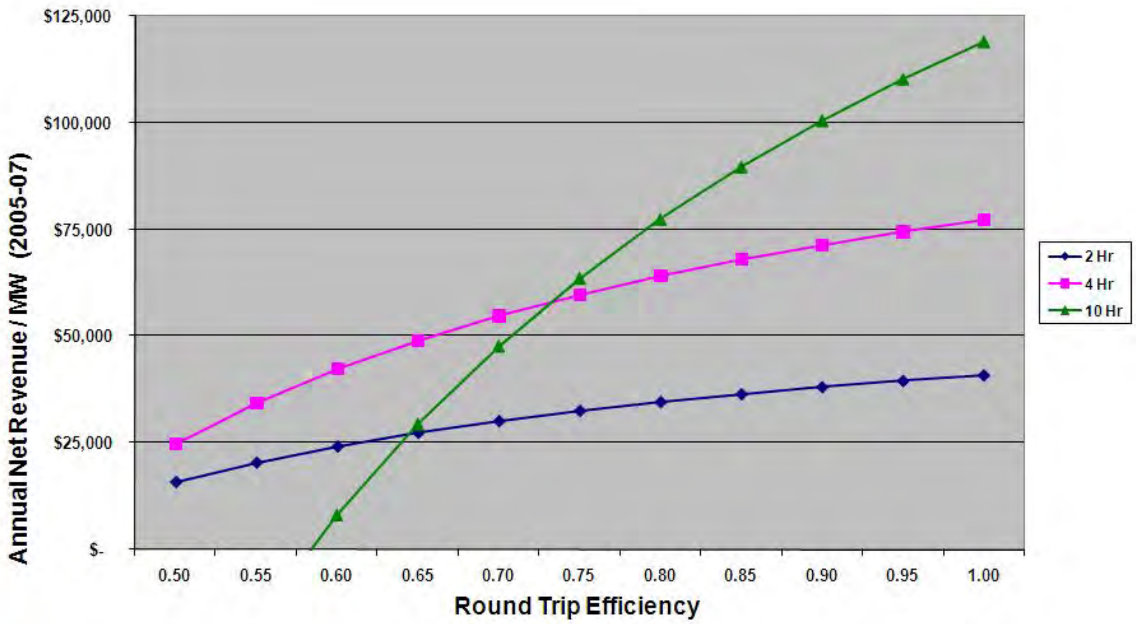


Figure 3-8: Effect of round-trip efficiency on annual net revenues from energy arbitrage for PJM South (BGE)

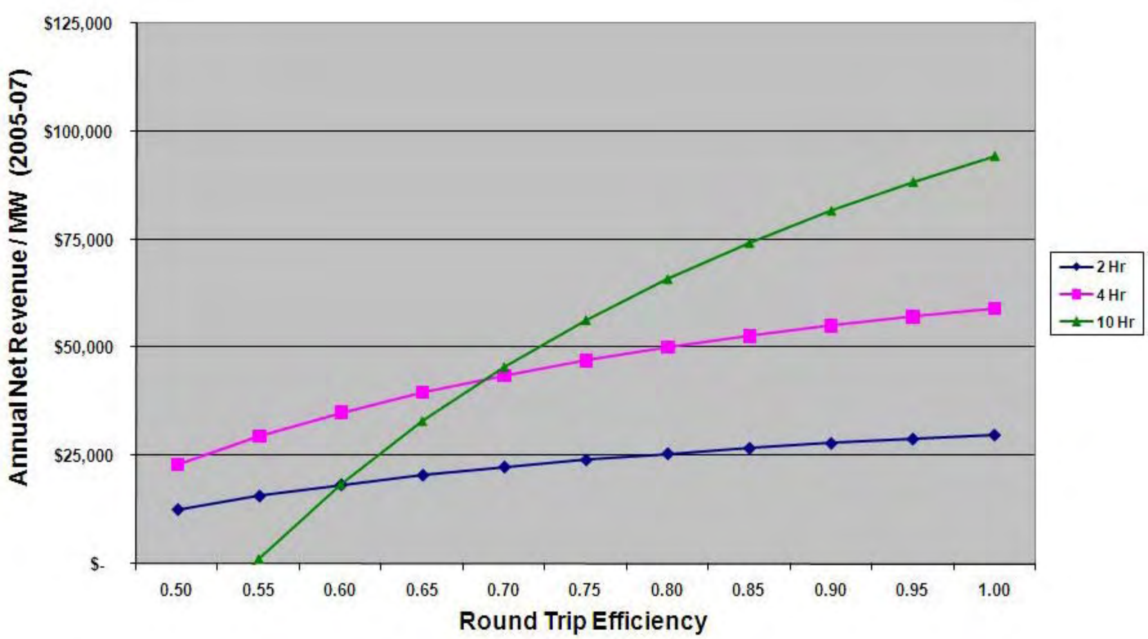


Figure 3-9: Effect of round-trip efficiency on annual net revenues from energy arbitrage for PJM West (AEP)

3-4. Capacity market revenues

In addition to energy arbitrage revenues, NaS batteries can also receive capacity payments from PJM. PJM has two capacity markets (daily and long-term). Until 2007, PJM had a single price for capacity resources located anywhere in the PJM territory. Table 3-6 provides a summary of load-weighted average capacity prices based on transactions in various capacity auctions (daily and long-term) held by PJM from 1999-2006 (2008a).

Table 3-6: Summary of capacity auction results for PJM (1999-2006)

Year	$/ MW-Day	$/MW-Year
1999	$52.24	$19,068
2000	$60.55	$22,101
2001	$95.34	$34,799
2002	$33.40	$12,191
2003	$17.51	$6,391
2004	$17.74	$6,475
2005	$6.12	$2,234
2006	$5.73	$2,091

PJM recently restructured the capacity markets by introducing locational capacity markets as part of the Reliability Pricing Model (RPM) that was approved by FERC in 2007 (PJM 2007b). Table 3-7 shows 2007-2008 and future anticipated prices for capacity under RPM for representative zones within the four super-zones (PJM 2008c). Since historic capacity prices are no longer applicable, the range of annual capacity prices from Table 3-7 was used in calculating the total revenue potential for energy arbitrage in the different regions.

Table 3-7: Summary of capacity auction results for PJM under RPM (PJM 2008c)

		2007-08	2008-09	2009-10	2007-08	2008-09	2009-10
Zone	**Super-zone**	**Preliminary Zonal Capacity Price [$/MW-day]**			**Preliminary Zonal Capacity Price [$/MW-Year]**		
BGE	**PJM South**	**$188.05**	**$210.11**	**237.33**	**$68,639**	**$76,690**	**$86,625**
PECO	**PJM East**	**$197.16**	**$148.80**	**191.32**	**$71,963**	**$54,312**	**$69,832**
PENLC	**PJM Central**	**$40.69**	**$111.92**	**191.32**	**$14,853**	**$40,851**	**$69,832**
AEP	**PJM West**	**$40.69**	**$111.92**	**102.04**	**$14,853**	**$40,851**	**$37,245**

3-5. Ancillary service revenues

As explained in section 1-5, PJM markets allow EES resources to provide ancillary services. Currently EES can participate in the two ancillary service markets operated by PJM: regulation and synchronized (or spinning) reserve. Regulation service helps PJM maintain the stability of the power system in order to correct short-term changes (within 5 minutes) in load and supply. Synchronized reserves are used in case of unexpected power requirements within 10 minutes.

3-5-1. Regulation revenues

Regulation service is traditionally accomplished by committing online generators whose output can be raised or lowered, usually in response to an Automatic Generation Control (AGC) signal, as necessary to follow changes in load. The control signal is generated every six seconds. PJM requires a regulation resource to respond to the regulation signal within five minutes. The regulation requirement is 1% of peak load in PJM (PJM 2007c). As shown in Figure 3-10, PJM integrated various regulation control zones into a single regulation market region in August 2005.

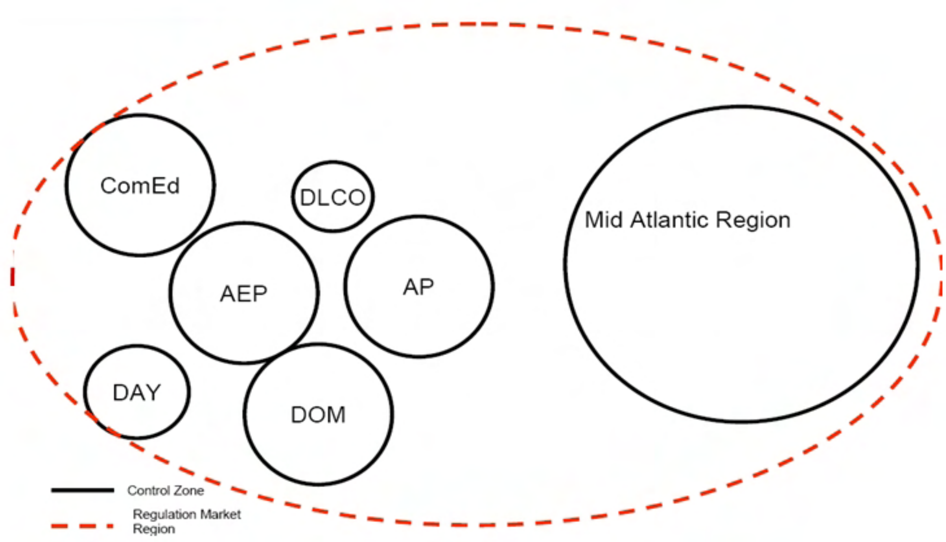


Figure 3-10: PJM single regulation market region (Source: PJM 2007c)

In PJM, the regulation price offers are capped at $100/MWh, but the generators are also eligible to receive additional payment for opportunity cost. The opportunity costs are paid to generators dispatched by PJM for regulation in 2 scenarios: If the generator has to increase its output when LMP is lower than the energy bid price for the generator (i.e. uneconomical operation) or if the generator is required to lower its output when LMP is greater than the bid price (i.e. lost revenue).

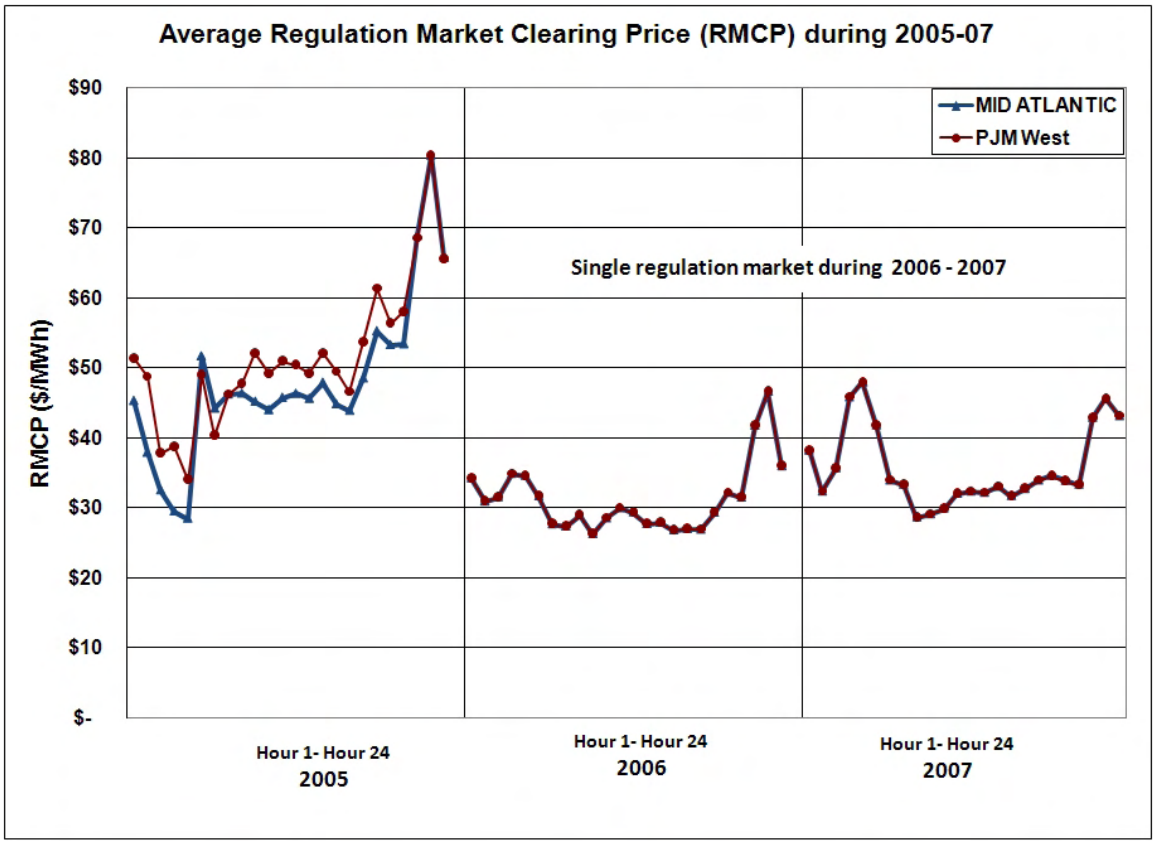


Figure 3-11: PJM regulation market clearing price curves (2005-2007)

Figure 3-11 shows the average daily prices curves for the regulation market clearing price (RMCP) for during 2005-2007. I have used the hourly RMCP prices during 2005-2007 to quantify the revenue potential for using flywheels to provide regulation service. While calculating the net revenue potential for regulation, a 15% energy cost was deducted from the regulation revenues to cover round-trip and standby losses of the flywheels.

It is important to note that a few issues may affect the revenue potential for regulation services in PJM markets in the future.

- Although traditionally it is expected that regulation service is a net energy zero service and the regulation signal will move in both directions (positive and negative), PJM recently has indicated that it may require the regulation signal to go in the same direction for longer duration.[6] This could result in an energy-limited resource such as a flywheel reaching the technical limit (either fully charged or fully discharged) for a considerable amount of time. Based on the sample regulation signal (for the first week of June 2006) provided by PJM[7], a flywheel would be able to provide regulation for only 58% of the time due to its energy-limited nature (15-minute duration). Under current market rules PJM will not penalize the flywheel for noncompliance if the noncompliance is a result of technical limitation. The test results from Beacon Power's demonstration project in California and New York indicate that flywheels have complied with the Area Control Error (ACE)[8] signal in respective control zones more than 90% of the time. At the same time, there is no certainty that a flywheel would be able to receive full regulation revenues or that the revenues would be pro-rated based on future compliance.

- The other issue related to regulation revenue for flywheels is based on the way PJM provides payments for regulation costs. As mentioned earlier in this section, generators are eligible to receive opportunity cost payments (based on lost revenue from the energy market) in addition to the RMCP payments. Under current rules, non-capacity resources such as flywheels that do not supply an energy bid are not eligible to receive opportunity cost

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[6] Based on personal communication with the PJM Market Support team and Mr. Ken Huber, Manager, Advanced Technology at PJM Interconnection.

[7] Sample regulation signal for the first week of June 2006 is available at http://www.pjm.com/markets/ancillary/downloads/regulation-signals.xls

[8] ACE represents the instantaneous balance of power flow within the control area. PJM uses regulation to control ACE by deriving the regulation signal from ACE for different control zones.

payments for providing regulation. Figure 3-12 shows the average RMCP and opportunity cost payments from the regulation market results for the period from August 2005 to February 2008. Based on these results it can be argued that the RMCP does not reflect the true price of regulation in PJM. For example, the average RMCP price for December 2007 was $26.96/MWh, but at the same time PJM also paid for opportunity cost, which resulted in an average additional payment of $23.41/MWh. This could provide generators an opportunity to suppress the regulation revenues that can be received by new technologies such as flywheels, by lowering the bids for regulation services and recovering costs through opportunity costs and reducing the revenue potential of flywheel. The 2007 market monitor report for PJM has already mentioned that the regulation market results for 2007 were insufficient to determine if the regulation market in PJM is competitive or noncompetitive. (PJM 2008a)

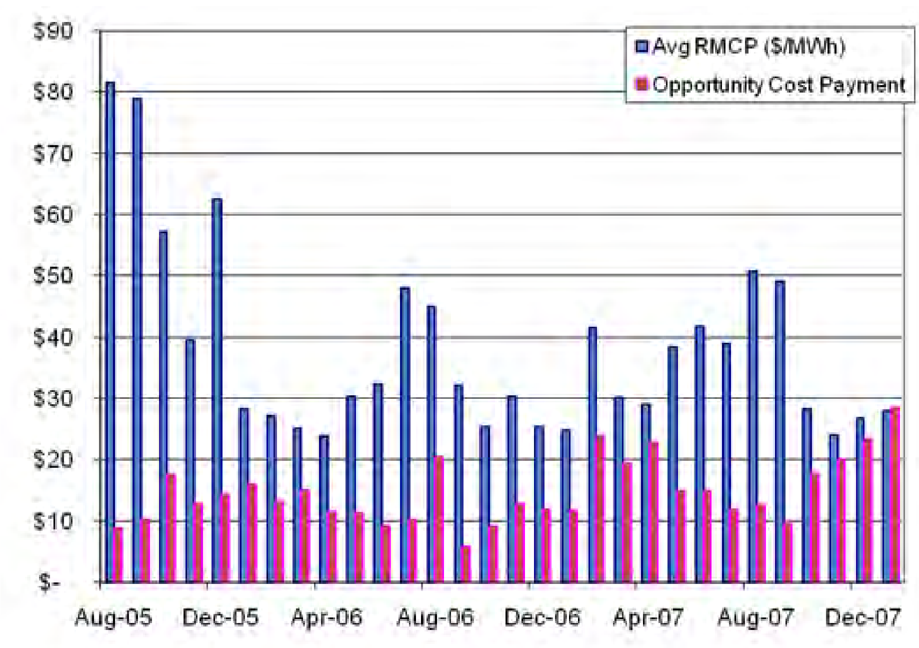

Figure 3-12: Average RMCP and opportunity cost payments in regulation markets from Aug. 2005 to Feb. 2008 (PJM, 2008e)

3-5-2. Synchronized reserve revenues

Synchronized reserves are used to provide compensation for a sudden loss in generation or transmission. Synchronized reserves must respond within 10 minutes and must be synchronized with the grid. PJM rules allow EES and demand response resources to participate in reserve markets as long as they have real-time telemetry in place and the resource can be directly dispatched by PJM (PJM 2007c).

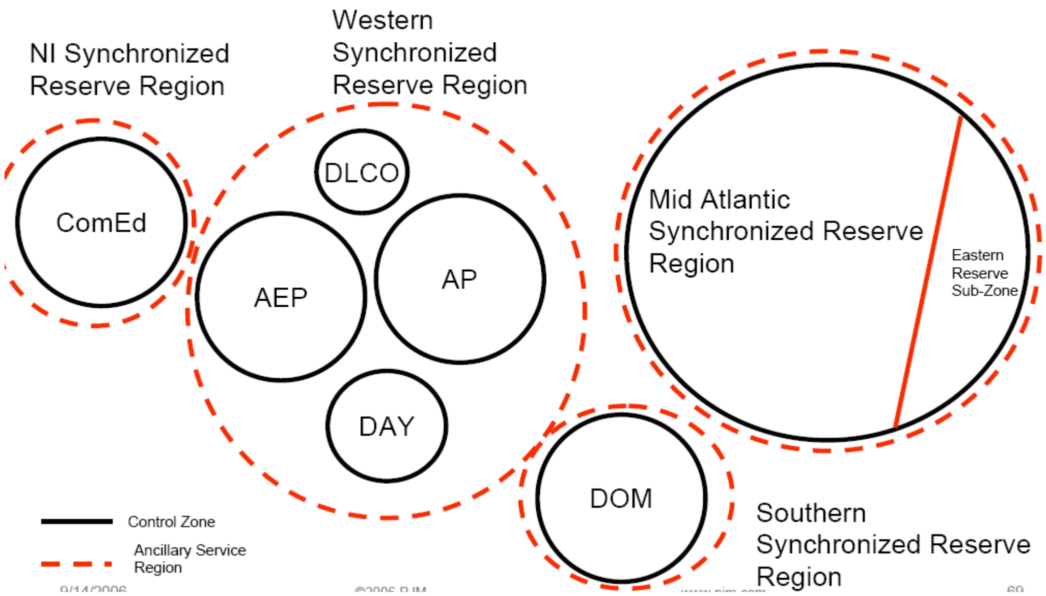

Figure 3-13a: PJM synchronized reserve market regions prior to 2007 (Source: PJM 2007c)

As shown in Figure 3-13a, PJM used to operate four different regions for synchronized reserves: the Northern Illinois Synchronized Reserve region, Western Synchronized Reserve region, Southern Synchronized Reserve Region, and Mid Atlantic Synchronized Reserve region. These regions were unified (except for Southern region comprising of Dominion zone) in a single market in early 2007 as shown in Figure 3-13b.

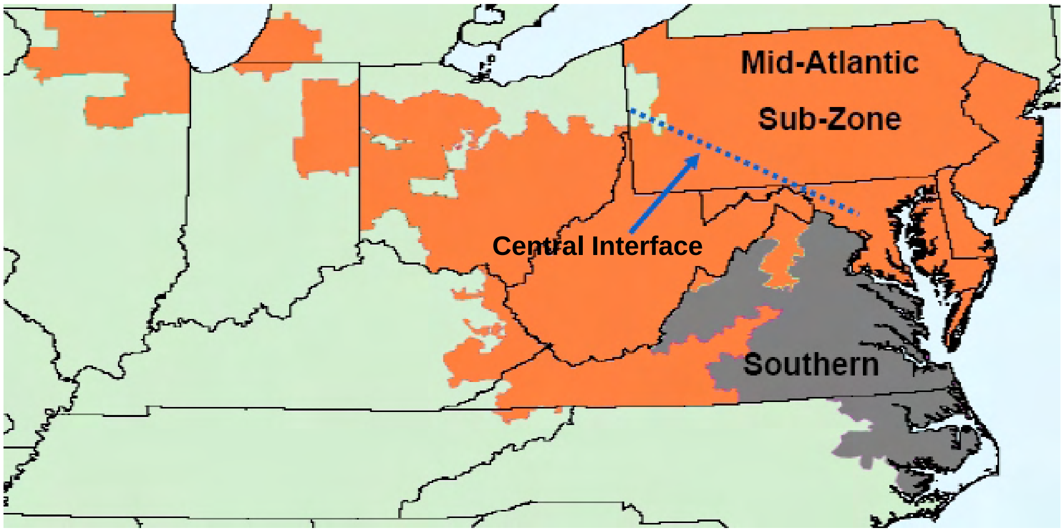

Figure 3-13b: PJM Synchronized Reserve Market Zones since 2007 (Source: PJM 2007c)

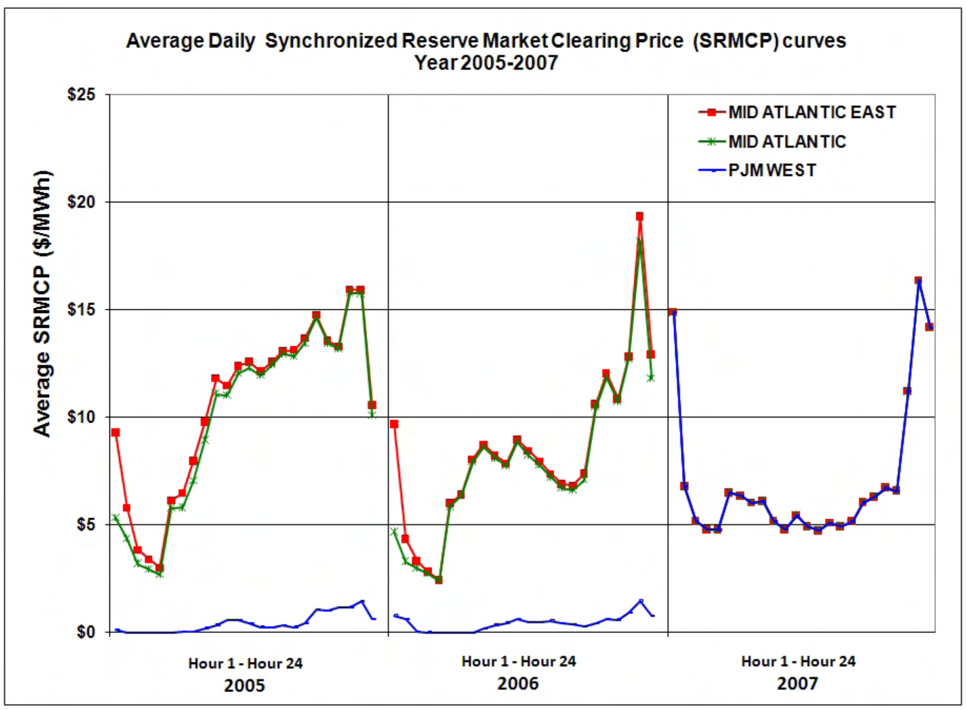

Figure 3-14: PJM Synchronized reserve Market Clearing Price (2005-07) (PJM, 2008f)

Figure 3-14 shows the daily synchronized reserve market clearing price (SRMCP) curves for 2005-2007 period. For year 2007, all the representative zones considered in this analysis were part of the unified PJM region and thus had same market clearing price for synchronized reserves.

NaS batteries can be used for providing synchronized reserves when not used for discharging or charging. Flywheels can not receive synchronized reserve revenues as PJM does not allow a unit to bid in both regulation and synchronized reserve market simultaneously (PJM 2007c). Thus I have used 15 hours of synchronized reserve revenues to supplement the 4-hour energy arbitrage revenue (the remaining 5 hours are used for charging the battery).

3-6. Estimating annual net revenues for different applications

As mentioned earlier, NaS batteries can be used for providing energy arbitrage, synchronized reserves, and capacity reserves, while a flywheel could be used for providing regulation service. Thus I have quantified annual net revenue potential for the following applications:

- NaS battery
    - Energy arbitrage (10 hours) + capacity reserve
    - Energy Arbitrage (4 hours) + synchronized reserve (15 hours) + capacity resource
- Flywheel
    - Regulation (24 hours)

Table 3-8 provides a summary of the net revenues that could be obtained by the EES operators in the PJM markets.[9] The minimum net revenues are for the year 2006, the maximum net revenues are for the year 2005, and the average revenues are calculated based on the average net revenues for 2005-2007.

Table 3-8: Summary of annual net revenue potential (based on 2005-2007 market data)

Application	Expected Net Revenues (Thousand$/ Year)											
	PJM East (PECO)			PJM South (BGE)			PJM Central (PENELC)			PJM West (AEP)		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Energy Arbitrage* (10Hours)	$89	$116	$141	$103	$124	$152	$43	$78	$118	$44	$78	$90
Energy Arbitrage* (4 Hours) + Synch Reserve (15 Hours)	$140	$177	$207	$155	$185	$218	$91	$138	$188	$53	$96	$127
Regulation (24 Hours)	$205	$255	$333	$201	$252	$332	$213	$266	$346	$219	$276	$389

* includes capacity revenues through RPM.

These results indicate that the PJM South region offers the highest potential for net revenues for NaS batteries, followed by PJM East and PJM Central. PJM West provides the lowest opportunity for NaS batteries. Although PJM regulation offers same regulation revenues for the entire territory, the PJM West region offers the best opportunity for using flywheels for regulation due to the lower cost for energy required to compensate for losses during regulation.

[9] *The differences in energy arbitrage net revenues across NYISO zones and PJM zones can be explained by observing the differences in capacity revenues as well as the differences in the average daily LMP curves over 2001-2007 shown in Figure A-3-5 in the Appendix.*

3-7. Net Present Value (NPV) analysis

As shown in Table 3-8, the expected net revenues for EES resources can vary from year to year. This uncertainty, which is due to fluctuations in energy prices, is incorporated into the analysis by performing a Monte Carlo simulation on the net present value of both NaS battery and flywheel across all four regions over a 10-year period. This simulation was performed for 1,000 iterations using a triangular distribution for the net revenue for 4-hour energy arbitrage combined with 15 hours of synchronized reserve for NaS batteries in all four regions. Using a triangular distribution of net revenue from regulation, similar simulations were also performed for flywheels. The minimum, maximum, and average values for net revenue were selected for each region based on the data presented in Table 3-8. Based on the explanation provided in section 2.8 of Chapter 2, additional benefits were valued at $150/kW-year for NaS installations (considering both reliability and power quality benefits) and $100/kW-year for flywheel installations (by considering only the power quality benefits). Additional simulations were run to quantify the effect of the estimated capital cost on the NPV of both a NaS battery installation (in PJM south) and a flywheel installation (in PJM West). Table 3-9 provides a summary of all the financial parameters used in the NPV simulations.

Table 3-9: Summary of financial parameters

	NaS Battery	Flywheel
Capital Cost ($/kW)	$1,500-$2,000-$3,000	$750-$1,500-$2,000
O&M Cost ($/kW-yr)	$30	$25
Disposal cost ($/kW)	$15	-
Round-trip Efficiency	75%	85%
Discount factor	10%	10%

The simulation results shown in Figure 3-15 indicate that flywheels have an expected positive NPV for the complete range of capital cost estimates. There is a 50% probability that the NPV would be at least $770,000 for the average capital cost estimate of $1500/kW. The mean NPV would increase to over $1,500,000 if the capital cost drops to $750 /kW. The mean NPV drops to approximately $275,000 if the capital cost is $3000/kW.

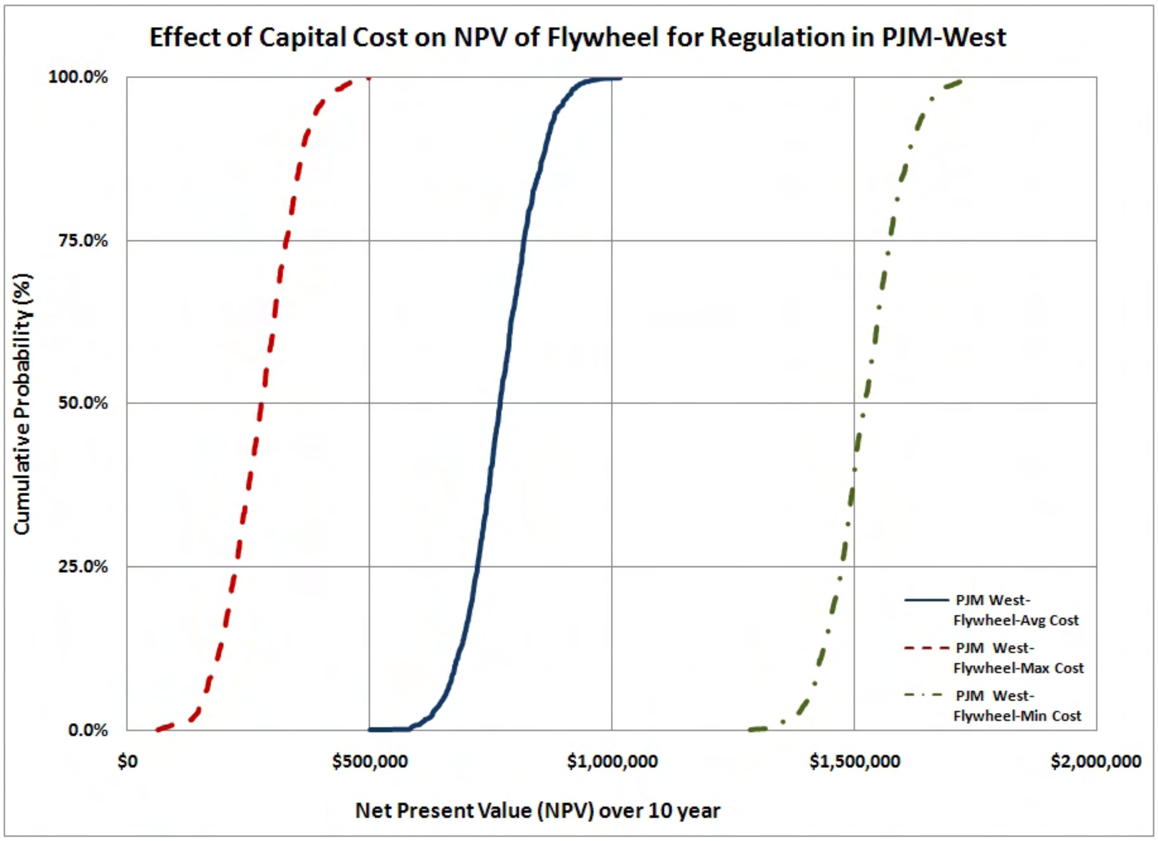

Figure 3-15: Effect of capital cost on NPV of flywheels for regulation in PJM-West

When the average capital cost estimate was used to simulate the NPV of using flywheels across the four PJM regions, the mean NPV was approximately $565,000 for PJM South, $580,000 for PJM East, and $650,000 for PJM Central, as shown in Figure 3-16. The highest revenue potential was obtained in PJM West with a mean NPV of $770,000.

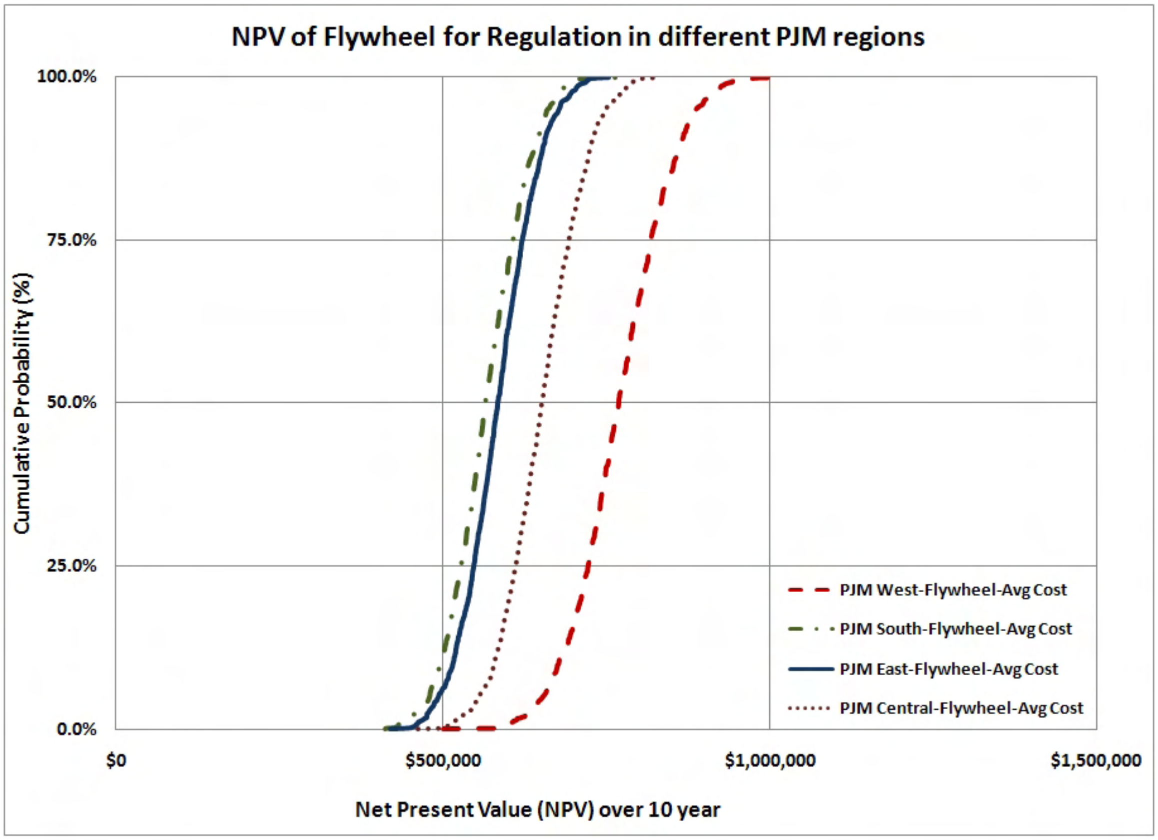

Figure 3-16: NPV of flywheels for regulation in different PJM regions for average capital cost

Similar simulations were conducted to evaluate the NPV of NaS batteries for providing energy arbitrage (4 hours) and synchronized reserve (15 hours), which offered the maximum net revenues for NaS batteries.

When the average capital cost estimate of $2,000 /kW for a NaS battery installation was used to calculate the NPV in all 4 regions of PJM, the NPV was negative for all cases as shown in Figure 3-17. The mean NPV for PJM South was -$140,000; for PJM East the mean NPV was -$215,000. The mean NPV for PJM Central dropped down to -$430,000. The PJM West region had the lowest mean NPV of -$720,000.

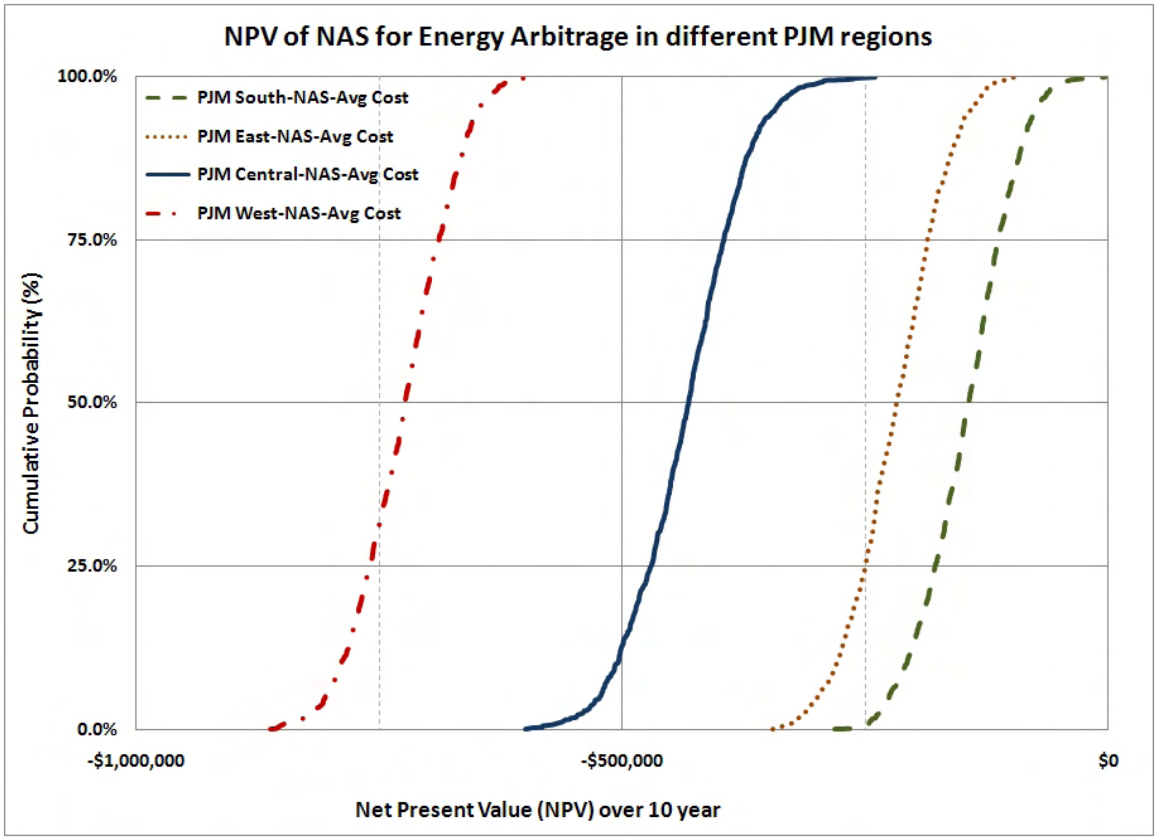

Figure 3-17: NPV of NaS for energy arbitrage and synchronized reserve in different PJM regions for average capital cost

A sensitivity analysis was performed by modifying the assumption for the capital cost for a best-case scenario of $1,500/kW and a worst-case scenario of $3,000/kW. The simulation results shown in Figure 3-18 indicate that the NPV of a NaS installation for providing energy arbitrage and synchronized reserve is positive only for the lowest capital cost estimate of $1,500 /kW. For the average cost estimate of $2,000 / kW the NPV is negative for 100% of the simulations. The mean NPV for the lowest cost estimate is approximately $350,000. The mean NPV for the average cost estimate ($2,000/kW) is -$140,000. For the highest cost estimate ($3000/kW) of a NaS battery installation, the mean NPV drops to -$1,100,000.

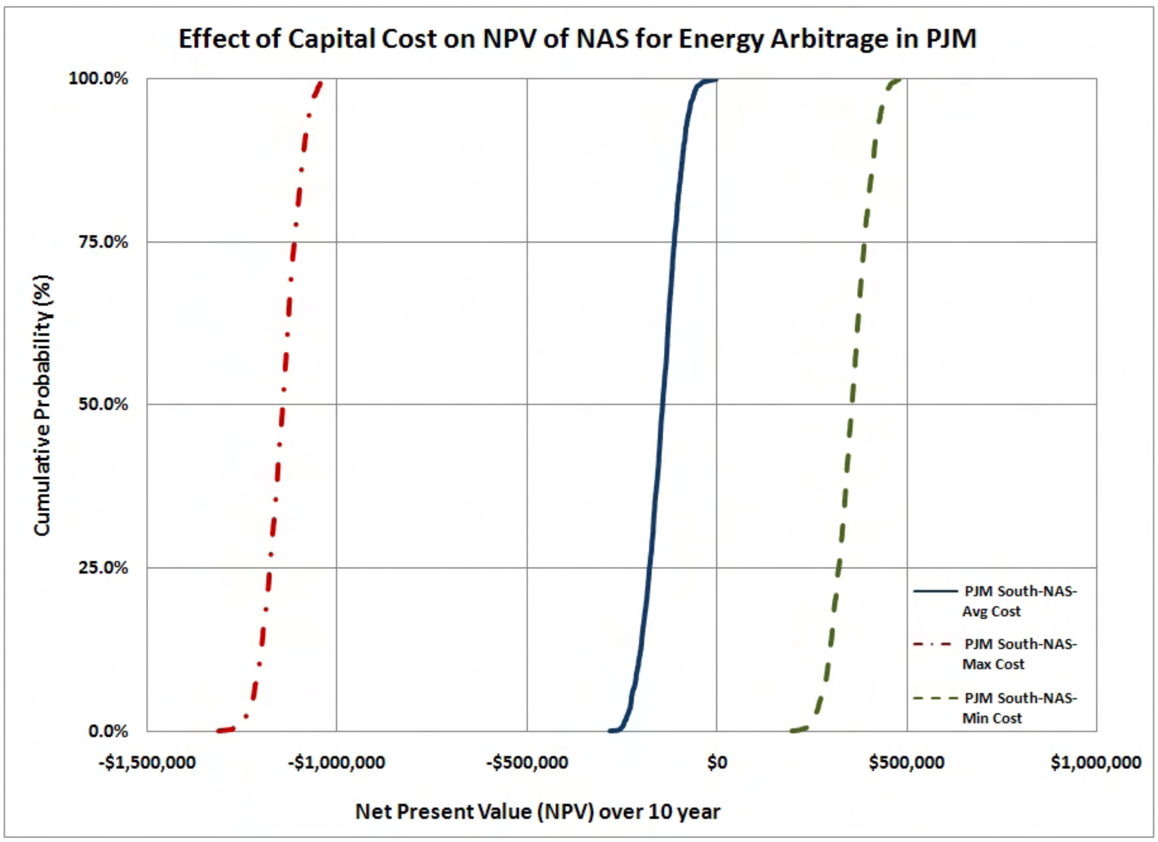

Figure 3-18: Effect of capital cost on NPV of NaS for Energy Arbitrage in PJM South

For the PJM South region, which offered the maximum revenue potential for a NaS battery, a sensitivity analysis was performed to evaluate the effect of round-trip efficiency on the NPV of a NaS installation. The results shown in Figure 3-19 indicate that even with the best-case scenario of 85% round-trip efficiency, there is only a 2.3% probability of a positive NPV for a NaS installation. The mean NPV for round-trip efficiency of 85% is -$80,000, which drops to -$230,000 for a NaS battery with round-trip efficiency of 65%.

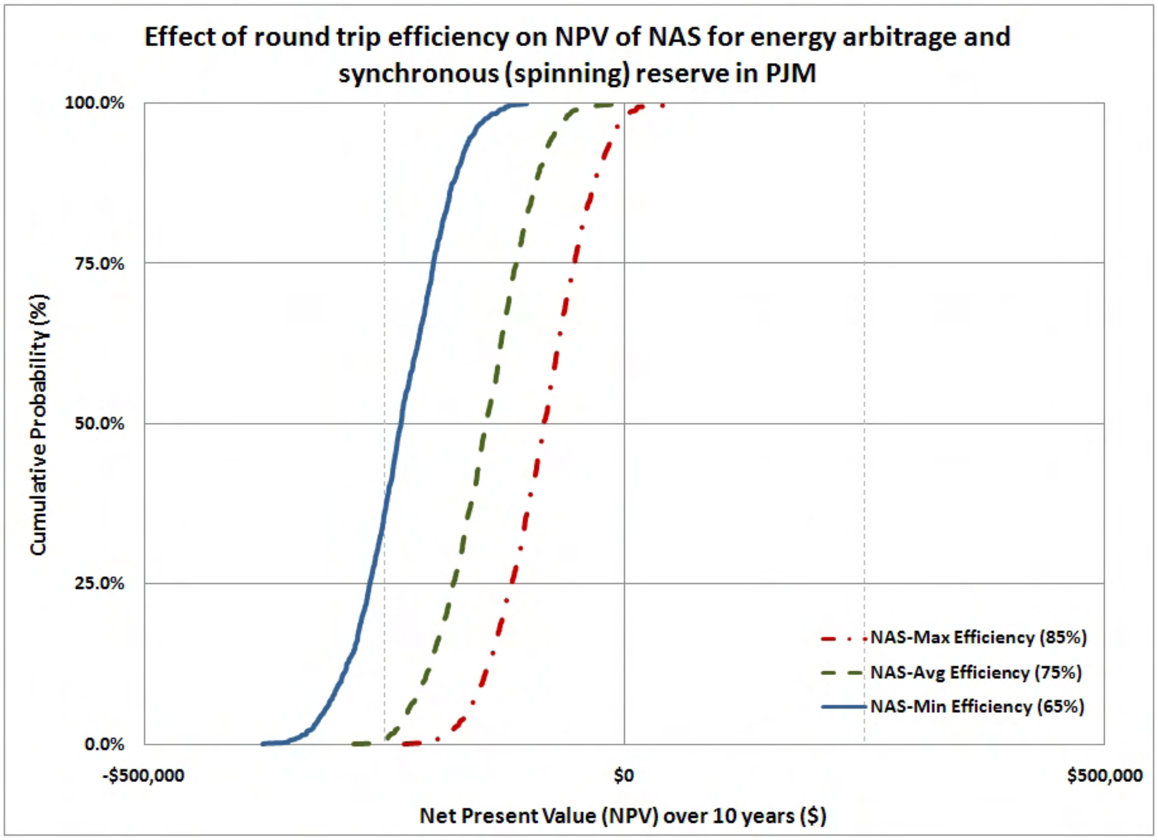

Figure 3-19: Effect of round-trip efficiency on NPV of NaS for energy arbitrage in PJM South for average capital cost

Figure 3-20 compares the NPV of a flywheel installation for regulation with the NPV of a NaS battery for energy arbitrage and synchronized reserves. These results indicate that unless the NaS installation cost drops below $2,000 /kW or there is a scenario where the NaS installation is able to generate additional benefits of more than $150,000 /MW-yr, there is no economic case for NaS in PJM for the average capital cost estimate. The current installation of a NaS battery by AEP at Charleston, West Virginia, is such an example, where AEP made a decision to invest in the NaS battery based on deferring substation upgrade costs of $2,000/kW. AEP plans to move the NaS battery after 2-3 years of field operation to different substations to maximize the savings in deferring the costs of upgrading substations. (Nourai 2006).

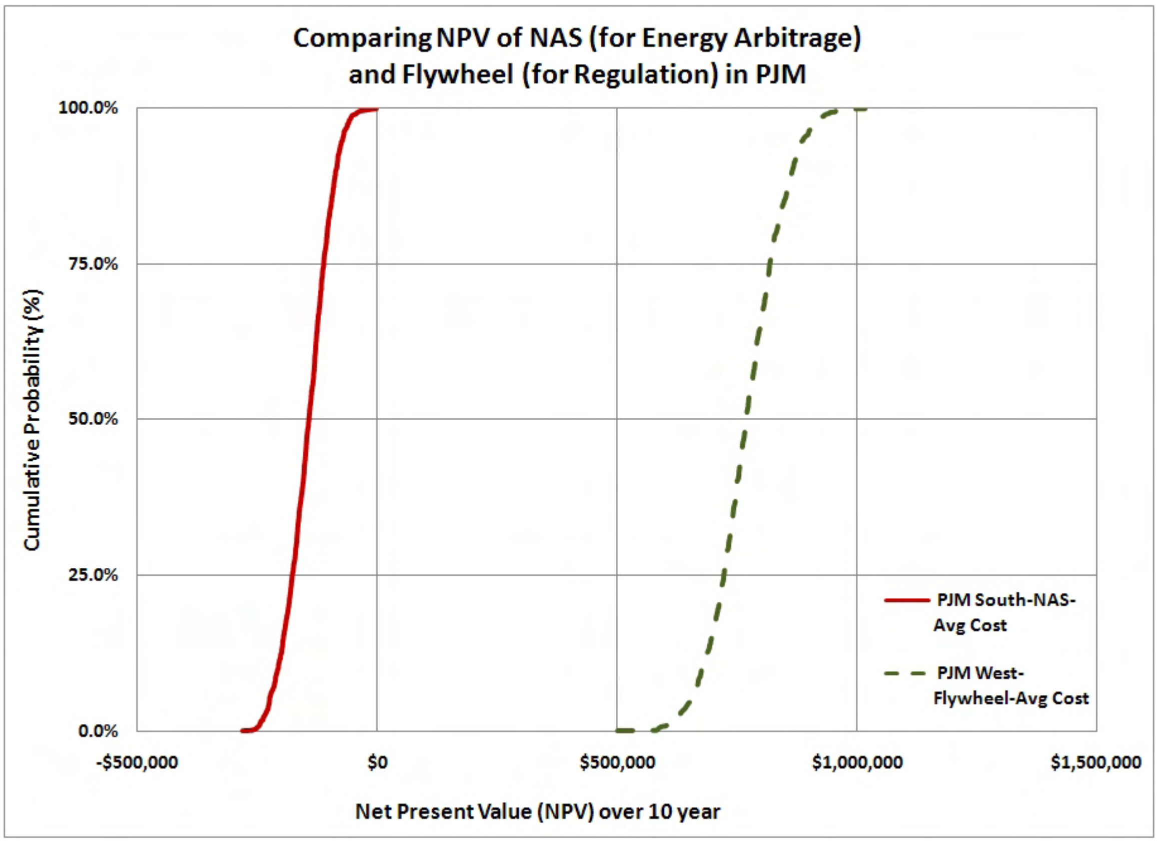

Figure 3-20: Comparison of NPV of NaS for energy arbitrage (PJM-South) and flywheel for regulation (PJM West) using the respective average capital costs

3-8. Comparing the economics of EES in NYISO and PJM

This section provides a summary comparison of the NPV analysis of NaS batteries and flywheels for the NYISO and PJM electricity markets. The comparison is provided by using the base case scenarios using the average capital cost for both technologies. For regulation, market results for NY West and PJM West regions were used as these regions offer the maximum net revenues for regulation in respective markets. For energy arbitrage, market results from NYC and PJM South regions were used for the same reason. The results are shown in Figure 3-21, 3-22 and 3-23.

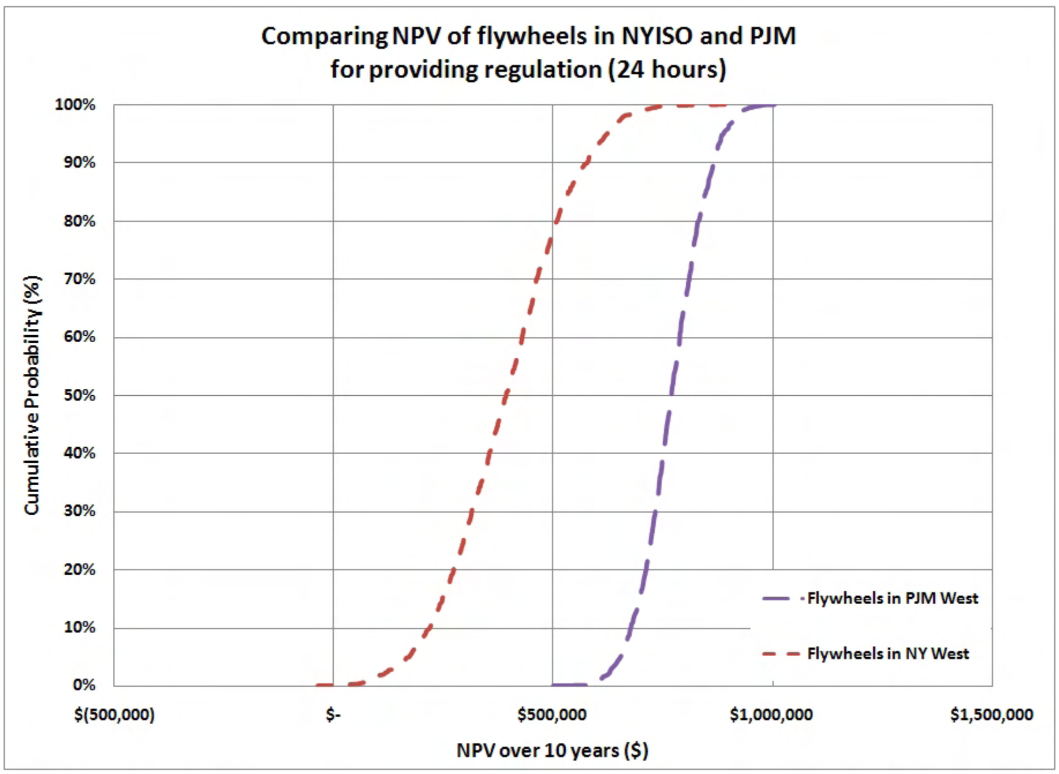

Figure 3-21: Comparison of NPV of flywheel for regulation in NYISO and PJM for average capital costs

Figure 3-21 indicates that the mean NPV of flywheels for providing regulation is positive in both NYISO and PJM. There is a 50% probability that NPV for flywheels will be approximately $390,000 in NYISO's NY West region and $770,000 in PJM in the PJM West region.

Similar comparison of NPV of NaS batteries for providing 4 hour energy arbitrage and 15 hours of synchronized reserves in NYISO (NYC region) and PJM (PJM South region) indicates that then mean NPV for both markets is negative. The mean NPV for NaS batteries in NYC is -$150,000 and -$140,000 in PJM South. The energy arbitrage revenue in NYISO has a larger uncertainty due to higher volatility in energy prices. There is a 2% probability of NaS batteries achieving a positive NPV in NYC region, whereas in PJM the NPV remained negative in all 1000 iterations.

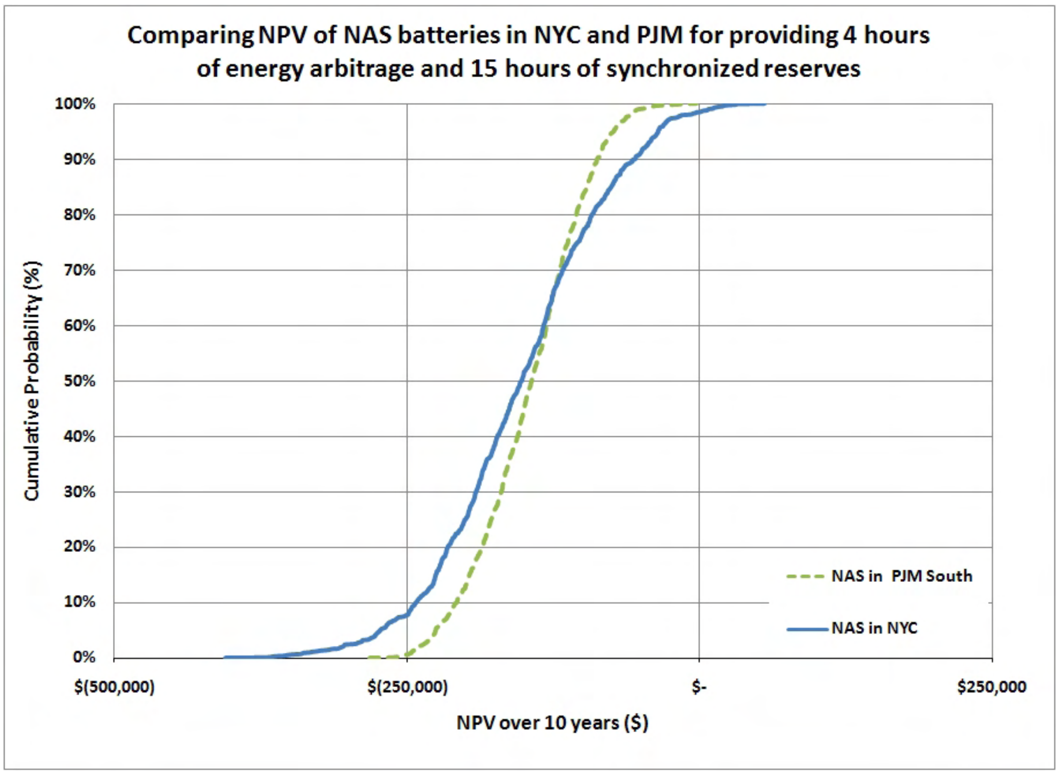

Figure 3-22: Comparison of NPV of NaS batteries for energy arbitrage and synchronized reserve in NYISO and PJM

Figure 3-23 provides a comparison of NPV of flywheels for regulation with NPV of NaS batteries for energy arbitrage and synchronized reserves in both PJM and NYISO markets.

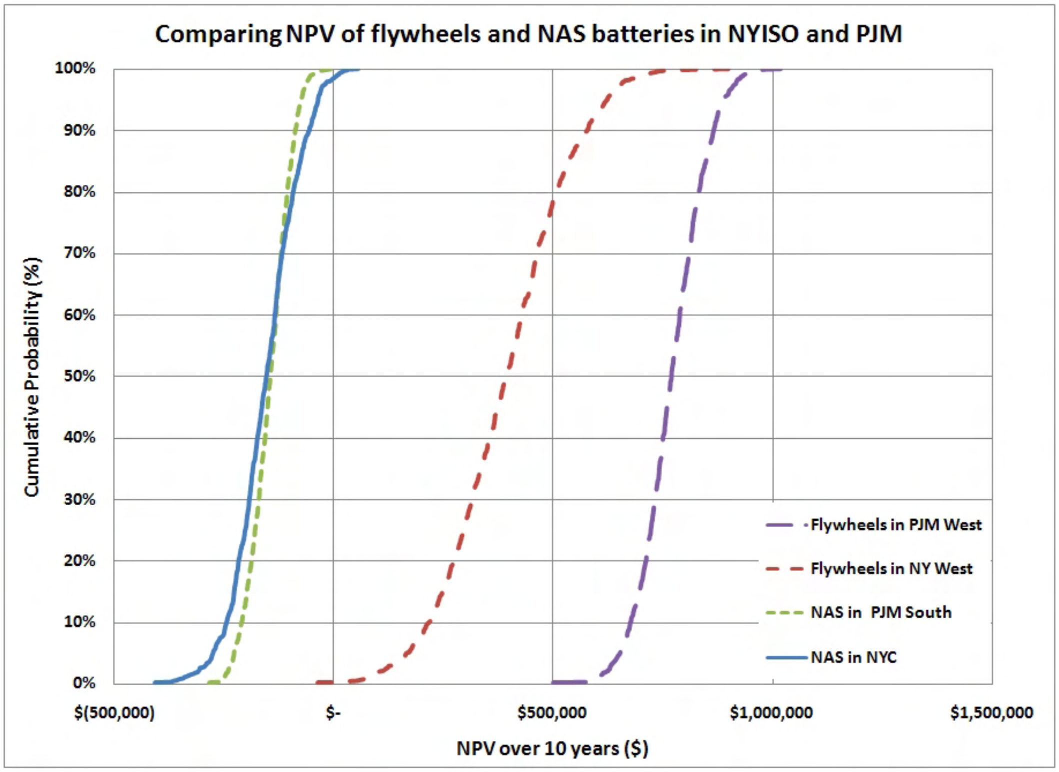

Figure 3-23: Comparison of NPV of flywheels and NaS batteries in NYISO and PJM

3-9. Conclusions

Similar to NYISO markets, PJM markets allow EES technologies to participate in the electricity markets. This research covered evaluation of flywheels for providing regulation, and NaS batteries for providing energy arbitrage and synchronized reserves in various PJM regions. Based on the current analysis of market data from 2005-2007, the regulation market offers the best opportunity for flywheels despite some uncertainties due to the energy-limited nature of flywheels.

There could be a substantial change in regulation revenues that can be captured by flywheels, if the regulation market rules are modified to address the two concerns listed in section 3-5-1. The sample regulation signal provided by PJM suggests that flywheels may be able to provide regulation for less than 60% of the duration. Although under current market regulations, flywheels are eligible to receive full regulation revenues, if PJM decides to pro-rate the payment based on the availability of a regulation unit, this could lower the regulation revenues significantly. On the other hand, if PJM allows flywheels to receive additional payments similar to opportunity cost payments received by traditional generation units used for regulation, then the revenue potential could be significantly higher. These uncertainties related to regulation revenue seem to be one of the major concerns regarding installations of flywheels for regulation. Beacon Power, the manufacturer of these flywheels, has now decided to build on its own a 20 MW regulation plant comprising 200 flywheels. Beacon power is in the process of identifying a suitable location in PJM, NYISO, or ISO-New England (Beacon 2007).

The analysis of PJM market data from 2005-2007 indicates that current market-based revenue streams are not sufficient to justify investment in NaS batteries for energy arbitrage and synchronized reserves in any of the PJM regions covered in this study. This analysis indicates that capital cost reduction is one of the major improvements required for NaS batteries to become economical for providing energy arbitrage in PJM. It is also important not to sacrifice efficiency as a means for reducing the capital cost, as lower round trip efficiency will reduce the net revenue potential from energy arbitrage.

However even with the lack of clear positive NPV for NaS batteries, market participants may invest in such installations if it is possible to combine the market based revenues with traditional benefits offered by EES as shown by the sensitivity analysis in appendix 2-A-5. AEP has justified the investment in the 1.2 MW, NaS battery installation at Charleston, WV based on the anticipated savings in substation upgrade deferral. AEP expects to utilize the NaS battery to defer a capital investment of $2000/kW in substation upgrade. (Nourai, 2006) AEP also has plans to install a 2 MW NaS battery near Milton, W.Va., to enhance reliability and allow for continued load growth in that area. AEP is planning to install a 2 MW NaS battery unit near Findlay, Ohio, to enhance reliability, provide support for weak sub-transmission systems and avoid equipment overload. (AEP, 2007).

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http://www.pjm.com/markets/jsp/ap-spinning-reserve.jsp (Pre-February 2007)

http://www.pjm.com/markets/jsp/sync-reserve.jsp (Since February 2007)

Appendix 3-A-1. Distribution of zonal LMP prices

Appendix 3-A-1 shows the summary of the statistical analysis of zonal LMP prices for 17 PJM zones for different periods: the complete year, the summer capability period, and the winter capability period based on 2005-2007 data. For PJM's operations the on-peak period is defined as hours between 7:00 am and 11:00 pm (prevailing Eastern Time) on non-holiday weekdays. The off-peak period is defined as are all those hours not defined as on-peak i.e. hours between 11:00 pm and 7:00 am (prevailing Eastern Time) on weekdays and all day Saturday, Sunday and NERC defined holidays. The summer capability period is defined as May 1st through October 31st and the winter capability period as November 1st through April 30th.

Table 3-A-1: Regional distribution of peak LMP prices ($/MWh) for 2005-07

Region	Zone	2005	2006	2007
PJM Central	APS	$73.35	$58.32	$68.95
	PENELEC	$71.57	$56.77	$66.54
PJM East	AECO	$88.76	$68.16	$78.04
	DPL	$85.23	$65.31	$76.17
	JCPL	$84.34	$63.44	$78.54
	METED	$82.25	$65.31	$76.43
	PECO	$85.16	$64.60	$75.22
	PPL	$81.31	$63.54	$74.03
	PSEG	$87.11	$66.33	$79.41
	RECO	$83.57	$66.14	$78.83
PJM South	BGE	$83.41	$67.26	$80.18
	DOM	$90.75	$64.95	$76.66
	PEPCO	$85.03	$68.59	$81.03
PJM West	AEP	$61.82	$51.91	$59.45
	COMED	$61.24	$51.73	$59.55
	DAY	$60.51	$50.85	$59.11
	DUQ	$58.12	$48.72	$57.04

Table 3-A-2: Regional distribution of peak LMP prices ($/MWh) for the summer capability period 2005-07

Region	Zone	2005	2006	2007
PJM Central	APS	$73.35	$58.32	$68.95
	PENELEC	$71.57	$56.77	$66.54
PJM East	AECO	$88.76	$68.16	$78.04
	DPL	$85.23	$65.31	$76.17
	JCPL	$84.34	$63.44	$78.54
	METED	$82.25	$65.31	$76.43
	PECO	$85.16	$64.60	$75.22
	PPL	$81.31	$63.54	$74.03
	PSEG	$87.11	$66.33	$79.41
	RECO	$83.57	$66.14	$78.83
PJM South	BGE	$83.41	$67.26	$80.18
	DOM	$90.75	$64.95	$76.66
	PEPCO	$85.03	$68.59	$81.03
PJM West	AEP	$61.82	$51.91	$59.45
	COMED	$61.24	$51.73	$59.55
	DAY	$60.51	$50.85	$59.11
	DUQ	$58.12	$48.72	$57.04

Table 3-A-3: Regional distribution of peak LMP prices ($/MWh) for the winter capability period 2005-07

Region	Zone	2005	2006	2007
PJM Central	APS	$64.67	$54.73	$65.01
	PENELEC	$62.82	$54.79	$64.43
PJM East	AECO	$75.19	$63.57	$71.36
	DPL	$72.95	$61.53	$71.81
	JCPL	$73.98	$60.56	$77.01
	METED	$68.32	$61.02	$71.30
	PECO	$71.71	$61.21	$70.94
	PPL	$68.02	$60.73	$70.55
	PSEG	$75.11	$63.41	$77.11
	RECO	$72.35	$63.69	$78.07
PJm South	BGE	$68.00	$62.61	$73.43
	DOM	$85.50	$59.80	$71.03
	PEPCO	$68.91	$62.50	$74.14
PJM West	AEP	$56.42	$50.00	$56.04
	COMED	$55.71	$49.65	$56.04
	DAY	$55.64	$49.22	$55.71
	DUQ	$55.40	$47.06	$53.26

Table 3-A-4: Regional distribution of off-peak LMP prices ($/MWh) for 2005-07

Region	Zone	2005	2006	2007
PJM Central	APS	$44.87	$37.82	$42.60
	PENELEC	$43.81	$36.84	$41.12
PJM East	AECO	$51.67	$42.83	$49.79
	DPL	$51.22	$42.32	$49.55
	JCPL	$49.61	$40.67	$49.78
	METED	$49.78	$41.67	$48.69
	PECO	$50.75	$41.96	$49.05
	PPL	$49.16	$41.05	$47.76
	PSEG	$52.39	$42.74	$50.44
	RECO	$51.25	$42.81	$49.88
PJM South	BGE	$52.47	$45.35	$52.46
	DOM	$54.73	$45.62	$51.86
	PEPCO	$53.60	$46.55	$53.70
PJM West	AEP	$35.92	$32.29	$33.42
	COMED	$34.48	$31.80	$32.96
	DAY	$34.91	$31.22	$33.24
	DUQ	$33.92	$30.52	$32.15

Table 3-A-5: Regional distribution of off-peak LMP prices ($/MWh) for the summer capability period 2005-07

Region	Zone	2005	2006	2007
PJM Central	APS	$44.87	$37.82	$42.60
	PENELEC	$43.81	$36.84	$41.12
PJM East	AECO	$51.67	$42.83	$49.79
	DPL	$51.22	$42.32	$49.55
	JCPL	$49.61	$40.67	$49.78
	METED	$49.78	$41.67	$48.69
	PECO	$50.75	$41.96	$49.05
	PPL	$49.16	$41.05	$47.76
	PSEG	$52.39	$42.74	$50.44
	RECO	$51.25	$42.81	$49.88
PJM South	BGE	$52.47	$45.35	$52.46
	DOM	$54.73	$45.62	$51.86
	PEPCO	$53.60	$46.55	$53.70
PJM West	AEP	$35.92	$32.29	$33.42
	COMED	$34.48	$31.80	$32.96
	DAY	$34.91	$31.22	$33.24
	DUQ	$33.92	$30.52	$32.15

Table 3-A-6: Regional distribution of off-peak LMP prices ($/MWh) for the winter capability period 2005-07

Region	Zone	2005	2006	2007
PJM Central	APS	$45.17	$40.06	$44.73
	PENELEC	$43.61	$38.92	$43.43
PJM East	AECO	$50.64	$44.51	$51.69
	DPL	$50.55	$44.48	$52.32
	JCPL	$50.09	$43.22	$53.90
	METED	$49.01	$44.18	$51.58
	PECO	$49.94	$44.17	$51.80
	PPL	$48.49	$43.62	$50.96
	PSEG	$50.73	$44.87	$53.18
	RECO	$49.60	$44.90	$52.53
PJm South	BGE	$50.91	$47.73	$55.36
	DOM	$62.41	$47.46	$54.64
	PEPCO	$51.79	$48.66	$56.66
PJM West	AEP	$36.80	$33.86	$34.94
	COMED	$34.29	$32.91	$34.44
	DAY	$35.80	$32.27	$34.54
	DUQ	$34.64	$31.21	$33.72

Appendix 3-A-2. Determining operating hours for energy arbitrage

Appendix 3-A-2 shows the results of the analysis performed to determine the operating hours for 4-hour energy arbitrage in each of the 4 super-zones.

Figure 3-A-1 shows the distribution for the 4 hour maximum revenue period during summer capability period during 2005 and 2006 for all 4 super zones. During the summer capability months the 4 hour period is 15:00 to 18:00.[10] the most common period for maximum revenue. The maximum revenue period for 4 hour energy arbitrage operations shift to period ending at 18:00 (i.e. from 5:00 pm) during the winter capability period as shown in Figure 3-A-2. The least cost period used for charging the EES during the 4 hours energy arbitrage operations does not show such seasonal shift. Figure 3-A-3 shows that the minimum cost period for all regions during the year is 2:00 to 5:00.

[10] PJM uses the convention of hour ending with. Thus hour 15:00 refers to hour ending at 15:00 i.e. hour that began at 14:00:01.

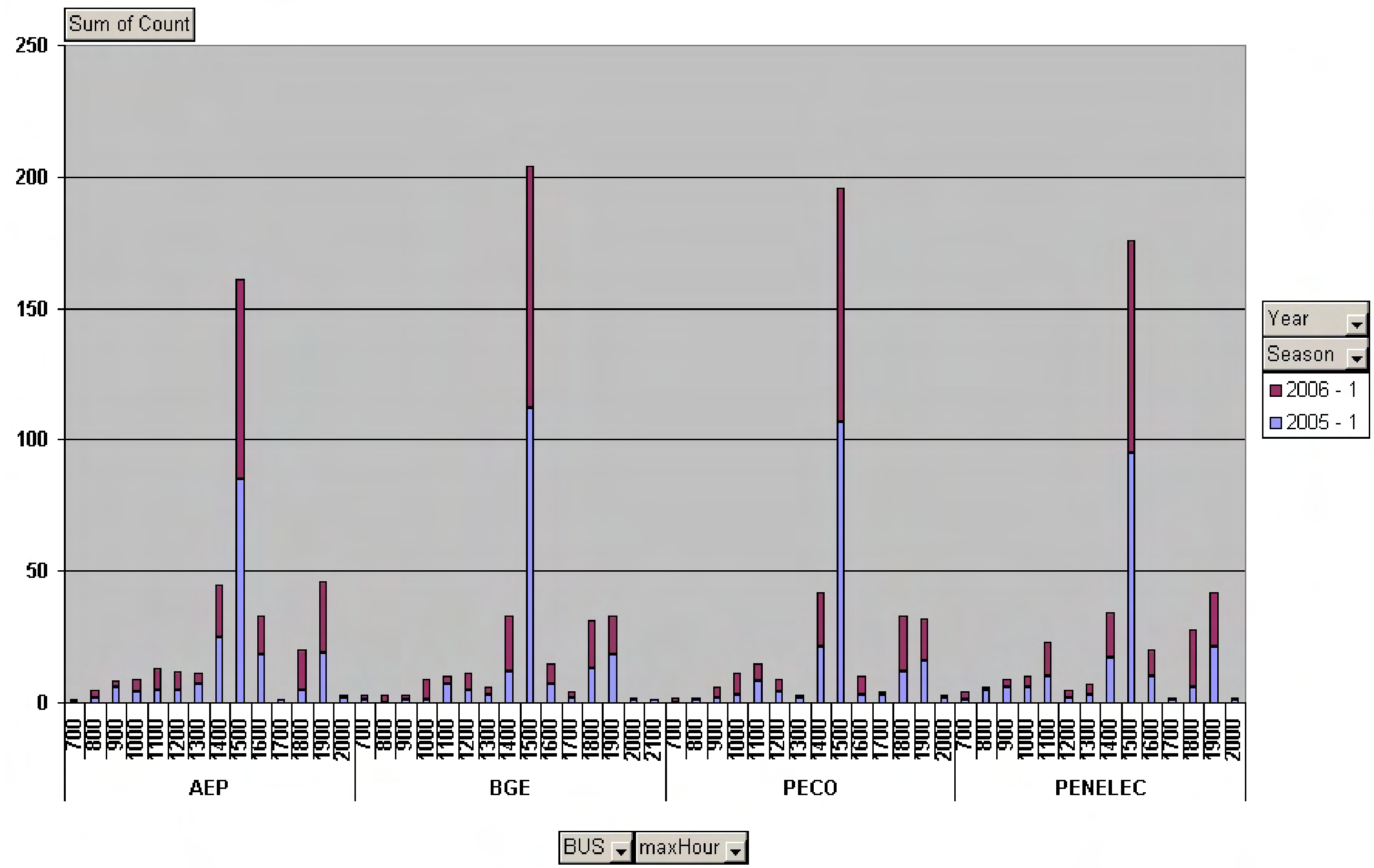

Figure 3-A-1: 4-Hour maximum revenue period during summer capabilities months (i.e. May – October)

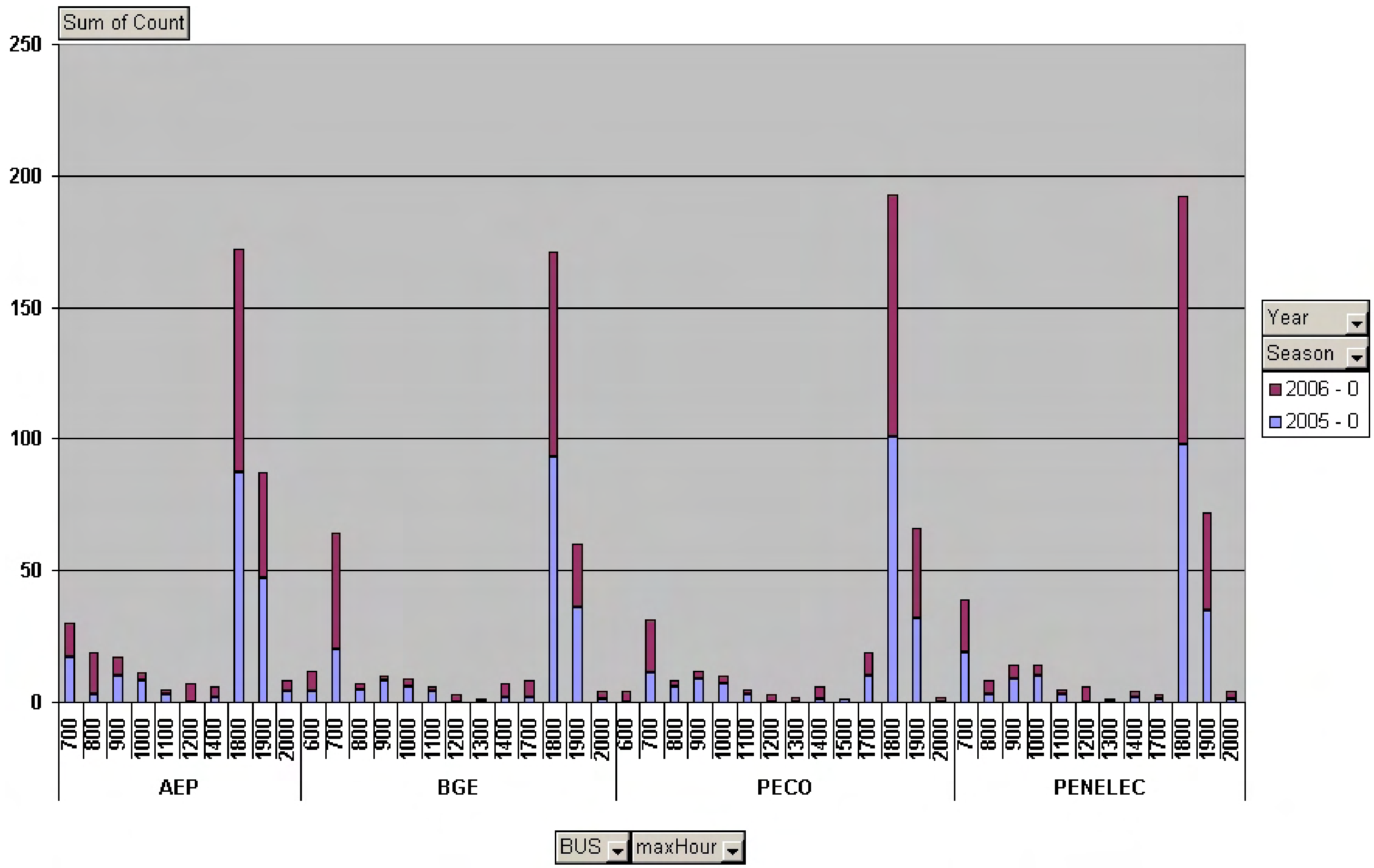

Figure 3-A-2: 4-Hour maximum revenue period during winter capabilities period (i.e. November – April)

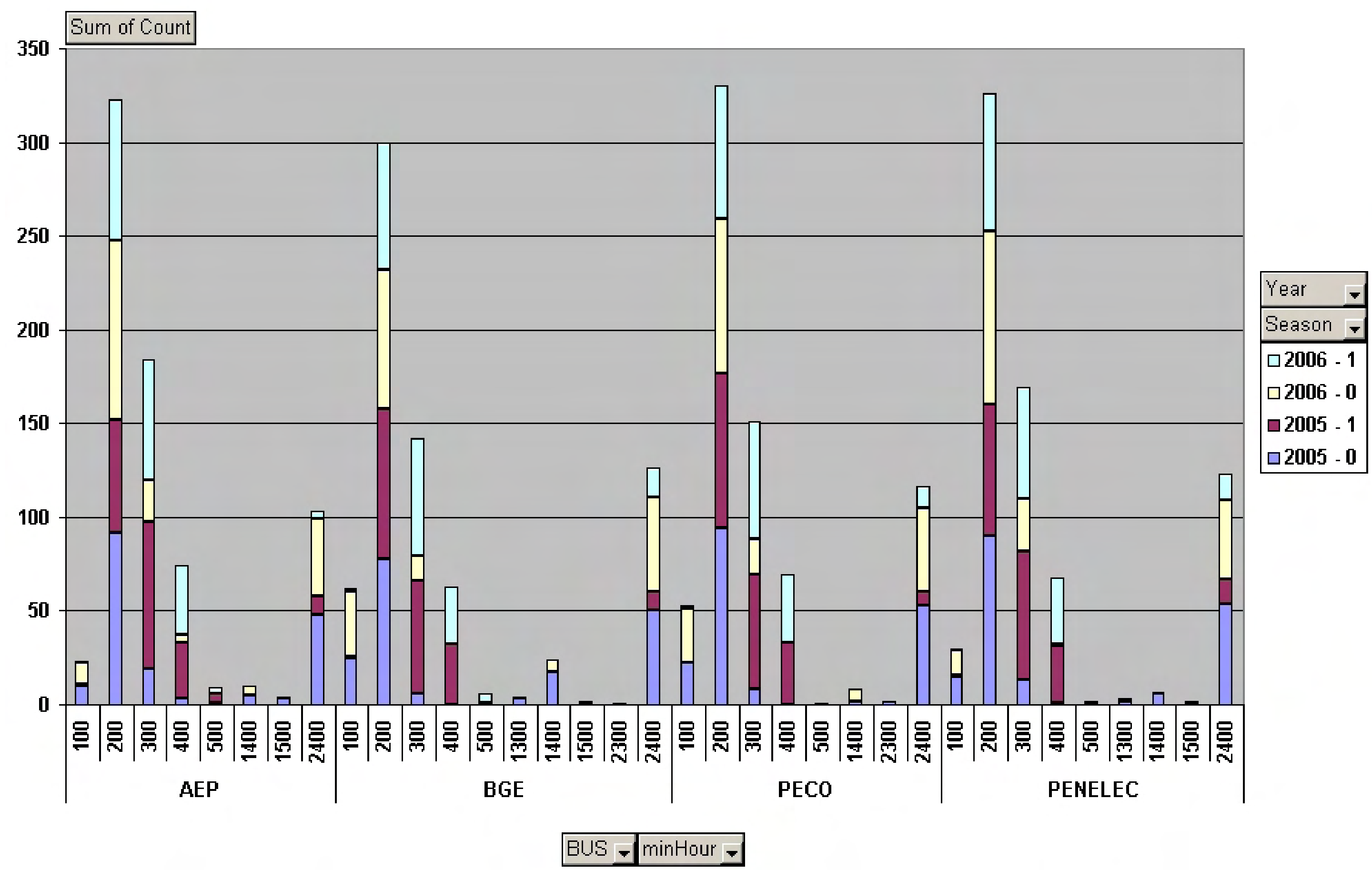

Figure 3-A-3: 4-Hour minimum charging cost period during complete year (includes both summer and winter capabilities periods)

Appendix 3-A-3. Sensitivity analysis for financial input parameters of NPV for NaS batteries for energy arbitrage

I performed a sensitivity analysis to determine the most important factors influencing the economics of NaS batteries for energy arbitrage in the PJM South region. Table 3-A-7 summarizes the range of input parameters used for the sensitivity analysis.

Table 3-A-7: Range for financial parameters used for sensitivity analysis.

Input Variable	Low	Base	High
T&D Benefits ($/kW-Year)	$0	$150	$300
Capital Cost ($/kW)	$1,500	$2,000	$3,000
Annual Revenues ($/MW)	$200,000	$235,000	$280,000
Charging Cost ($/MW)	$45,000	$52,000	$60,000
O&M Costs ($/kW-Year)	$20	$30	$50
Efficiency	65%	75%	85%
Discount Factor	5%	10%	15%

The base case had a NPV of -$238,000. Figure 3-A-4 shows the results of the sensitivity analysis as a tornado plot. Each bar indicates the variability in the NPV as a result of changing an individual factor. For example, the NPV will increase from -$238,000 to $680,000 if the installation can be used at a location which offers T&D benefits of $300 / kW-Year. Also the NPV will increase to $260,000 as compared to the base case if the capital cost is reduced to $1,500 /kW from the base case assumption of $2,000/kW.

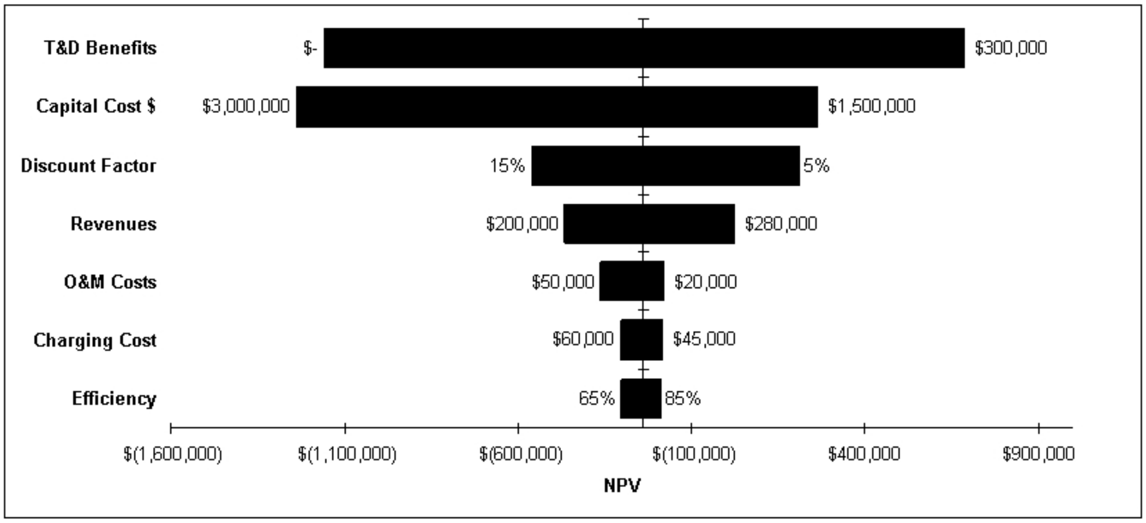

Figure 3-A-4. Sensitivity analysis for the net present value (NPV) of a NaS installation for 4 hours energy arbitrage in PJM South.

Chapter 4: An Economic Welfare Analysis of Demand-response in the PJM Electricity Market [11]

4-1. Introduction

When electric demand is at or near its peak level, very high-cost generating units must be utilized to meet the peak demand. Electricity prices in wholesale markets can increase from less than $50/MWh off-peak to hundreds of dollars per MWh at the peak hour.

In a competitive electricity market where all generators are paid the market-clearing price under a uniform price auction structure, even a small reduction in demand can result in an appreciable reduction in system marginal costs of production (Blumsack et al. 2006). Peak price events, although short in duration, add to the average cost per kWh to the consumer. The introduction of demand-response (DR) into constrained electricity networks can significantly lower peak energy costs and can potentially act as a check against the exercise of market power by generators (Talukdar, 2002; Rassenti et al., 2002; US-GAO, 2004; Violette et al., 2006a, 2006b; Brattle, 2007). Demand-response also has the potential to increase the long-run efficiency of the energy market (Borenstein, 2005).

Based on a review of current utility programs, the Electric Power Research Institute (EPRI) estimated that DR has the potential to reduce peak demand in the U.S. by 45,000 MW, roughly 5% (EPRI, 2002). The Brattle Group estimated that real-time pricing could provide annual benefits related to demand-response in the tens of millions of dollars, with further potential impacts on capacity and investment needs (Brattle, 2007). DR participation can be increased by providing better price signals, technology, and information, and then letting market participants respond to these price signals (Ruff, 2002). Studies have also identified the need for advanced

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[11] This research has been submitted to a peer reviewed journal for publication as: Walawalkar, R., Blumsack, S., Apt, J. and Fernands, S., 2008. An Economic Welfare Analysis of Demand Response in the PJM Electricity Market.

metering infrastructure (AMI) and building automation controls for enabling the potential of DR and energy efficiency (Lavy, et al., 2002).

In regulated vertically integrated markets, DR is considered as part of demand-side management (DSM) initiatives to delay network upgrades and investments in constrained networks (Violette et al., 2006a, 2006b). Since the introduction of deregulation in the early 1990s, DSM investments by utilities have declined significantly, as utilities in deregulated markets do not have financial incentives for investing in DSM (Loughran and Kulick, 2004). Recent research has also indicated that historically low participation in time-differentiated pricing programs, as well as the low short-run price elasticity of demand, can result in potentially large social welfare losses in deregulated markets. The welfare losses from low demand-response levels could be significantly reduced by introducing administered DR programs in concert with centralized energy spot markets. (Boisvert and Neenan, 2003)

This research focuses on demand-response markets run by U.S. Regional Transmission Organizations (RTOs). These programs generally include subsidies of one sort or another. I examine whether these subsidies introduce net deadweight losses or other distortions into the energy market, or whether they instead help correct the market failure caused by treating load as completely price-inelastic. I examine the economic welfare of the economic DR program that allows end-use customers to reduce load in response to price signals. This analysis focuses on one such program run by the PJM interconnection that can lower the peak demand in PJM through price-responsive load curtailments. The PJM Interconnection supplies electricity to over 50 million people in the United States, serving a peak load of 145,000 MW with 165,000 MW of generation, making it the world’s largest electricity market. While average hourly electricity prices in PJM’s real-time market were between \$49/MWh and \$58/MWh during 2005-07, peak prices went above \$200/MWh for 35 hours in 2005, 2006 and 2007 (Figure 4-1).

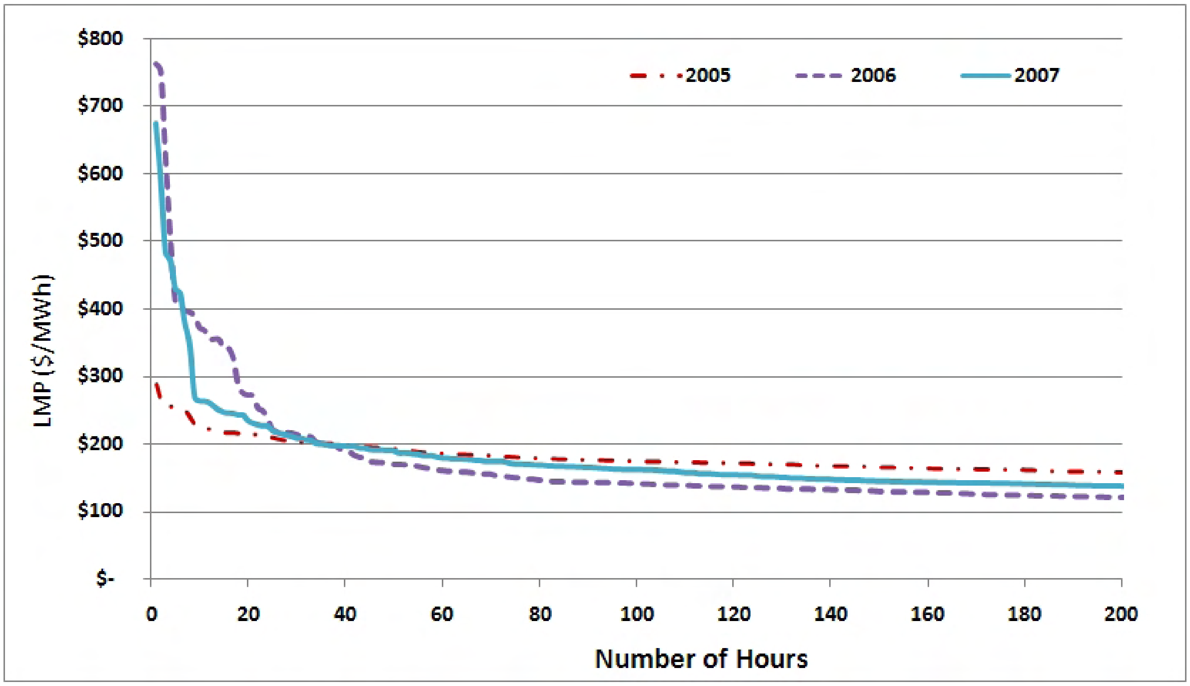

Figure 4-1: Price duration curve for the real-time market in PJM, top 200 hours during 2005-2007 (Source: PJM 2008b)

4-2. PJM's demand-response programs

Nearly all RTOs in the United States have some form of a market that enables customers or load aggregators to bid in demand reduction (Walawalkar et al., 2007). These DR programs allow customers to participate directly in real-time and day-ahead energy markets. PJM offers two types of DR programs:

Economic DR Program[12]: Under this program PJM pays the Locational Marginal Price (LMP) to customers if the LMP in a given zone is above a trigger point (set by PJM at $75/MWh). When the LMP is less than or equal to $75/MWh, PJM pays the customer the difference between the LMP and the generation and transmission (G&T) components of the customer's bill. PJM offers this economic DR program in both its day-ahead and real-time markets. A significant difference between the two is that there is no penalty for non-compliance in the real-time market, while successful bidding into the day-ahead DR market represents an obligation to curtail load.

Emergency DR Program: This is a voluntary program for reliability that offers energy payments to customers that reduce load during a system emergency. The payments are the higher of $500/MWh or the zonal LMP for the hour. There is no penalty for non compliance, and this program is rarely utilized by PJM (on average, less than twice a year).

End-use customers can participate in these DR programs by using either distributed generators or energy management control strategies to reduce their load in response to a price or emergency signal from PJM. Table 4-1 lists some of the control strategies used in economic or emergency DR programs.

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[12] The economic demand response program incentive structure modeled here was allowed to expire at the end of 2007. The subsidy payments described in this paper are no longer offered to DR market participants. The U.S. Federal Energy Regulatory Commission (FERC) upheld the expiration of the incentive payments in an order under Docket EL08-12-000, issued on 31 December 2007.

Table 4-1: Control Strategies for participation in DR programs for different customer types

(Adapted from Walawalkar et al. 2007)

Customer Type	Equipment / Building Component	Control Strategy
Residential	Air Conditioners	Cycling/forced demand shedding
	Water Heaters	Cycling
	Pool Pumps	Cycling
	Electric Stoves	Scheduling
Commercial	Chillers	Demand limiting during on peak period
	Chillers	Pre-cool building for over-night storage
	HVAC	Direct expansion (DX) forced demand scheduling
	Refrigerator/ Freezers	Prioritized demand shedding
	Lighting	Scheduled on/off
	Lighting	Scheduled dimming of selected circuits
Industrial	Chillers	Demand limiting on time schedule
	Electric Furnaces	Demand limiting through heat stages
	Electric Furnaces	Curtail (during peak period)
	Variable Speed Drives	Limit output on scheduled basis
	Well pumps	Defer during peak
	Production Equipment	Prioritized demand on selected units
Restaurants / Shopping Malls	HVAC	Chillers- demand limiting during peak
	DX Compressors	Forced demand shedding of multiple units
	Refrigerator/ Freezers	Prioritized demand shedding
	Electric Stoves	Scheduled pre-cooking

During 2006 there was 1,475 MW load registered under the economic DR program and an additional 1,081 MW load registered under the emergency DR program (Kujawski, 2007). However, during the summer of 2006, only 325 MW of DR cleared in the economic DR program during the peak load days (Covino, 2006). Thus, a distinction must be made between loads that are registered to participate in the PJM demand-response markets, and the amount of load that actually participates.

4-3. An economic model of the PJM demand-response market

In contrast to existing work that assumes 3% to 10% DR participation (e.g. Brattle, 2007 and Boisvert and Neenan, 2003), this analysis of the PJM economic DR program is based on actual participation data. Since the "emergency" DR program is called on very rarely (Table 4-2), it is not discussed here.

Table 4-2: Summary of PJM initiated emergency DR events (Source: PJM, 2007)

Year	No of events	Dates
2000	2	May 8 and 9
2001	4	July 25, August 8, 9 and 10
2002	3	July 3, 29 and 30
2003	0	None
2004	0	None
2005	2	July 27, Aug 4
2006	2	Aug 2 and 3
2007	1	Aug 8

As previously mentioned, PJM's economic DR program offered incentives for participation in the form of payments related to the LMP at the time the demand curtailment occurs (which may be different than the time a customer commits to demand curtailment). Under the economic DR program, the incentive was available once the LMP exceeds some trigger point, which I denote as LMP*. In its economic DR program, PJM had set LMP* equal to $75/MWh. The direct payment accruing to the *i*th market participant curtailing one megawatt of demand during hour *t* was calculated as follows:

$$\pi_{it} = \begin{cases} LMP_t & LMP_t \geq LMP^* \\ (LMP_t - GT_i) & GT_i < LMP_t < LMP^* \\ 0 & GT > LMP_t \end{cases} \tag{4-1}$$

where *GT* is the sum of the generation and transmission (G&T) components of the customer's monthly electric bill.[13] The direct payment for a market participant curtailing $Q_{Ri,t}$ megawatts of demand during hour *t* is given by $Q_{Ri,t} \times \pi_{it}$. The *R* in the subscript denotes demand reduction rather than the level of demand.

The decision by an individual consumer or curtailment service provider (CSP) to offer DR in the PJM market and the payment from actually curtailing demand do not occur simultaneously. In the day-ahead DR market, consumers bid binding demand-reduction commitments; the accepted curtailment bids must be honored 24 hours later. The real-time DR market operates differently. Each DR participant must notify PJM of its intent to curtail load at least one hour in advance. Load curtailment is compensated using the real-time LMP. The real-time demand-reduction commitments are non-binding: consumers incur no penalty for shortfall in curtailment. Since the

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[13] The G&T component can vary significantly from year to year due to changes in fuel costs. G&T charges may be based on customer class, as well as historical retail rates. For some industrial customers the G&T component could be as low as $30 /MWh, while for other customers the G&T component may be indexed to day-ahead or real-time LMP.

payment to the consumer depends on the prevailing LMP at the time that demand is actually curtailed, market participants are effectively basing a commitment to reduce demand at time *t* on an expectation of LMP at some previous time *t* – *k*. Market participants must decide whether to bid any demand reduction into the market, and then must decide what kind of demand-response "supply curve" to bid into the market. The most significant factor in the decision to bid DR is the expectation of the market-clearing price in PJM.

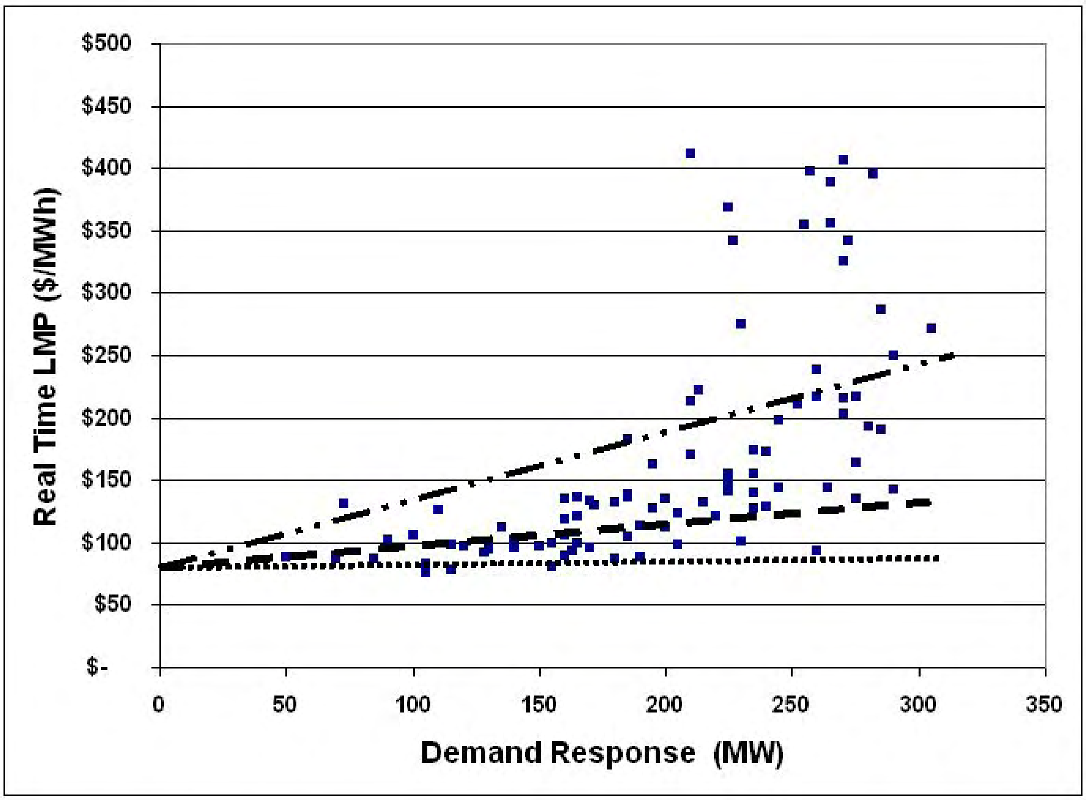

Figure 4-2: Load curtailment market results from the PJM economic demand-response market during six days in 2006 and three possible DR supply curves (Source: Covino, 2006)

Figure 4-2 shows a price-quantity plot of actual market-clearing bid data into the day-ahead and real-time PJM economic DR market (Covino, 2006). These data constitute the only price-quantity data released for PJM's economic DR program.

Although there was some DR activity below the incentive trigger point of $75/MWh, there is very little economic incentive for participation in the DR market at such low prices unless customers have low G&T rates. For example, if the LMP is $60/MWh and the customer's G&T rate is $50/MWh, the payment to the customer for providing DR services would be $60 - $50 = $10/MWh. When the LMP is lower than the G&T rate, a customer providing DR services to PJM receives no payment at all (Equation 4-1). Part of the observed activity below the trigger point under the real-time DR program can likely be explained by unanticipated variations in the real-time LMP, where the LMP dropped below $75/MWh unexpectedly (that is, DR was bid into the market on the incorrect expectation that prevailing prices would be higher than $75/MWh)[14]. Note that the direct payment π_{it} represents a transfer payment to the *i*th participant in the DR market from the rest of the participants in the system (generators, other participants in the DR market, and energy-market customers that do not offer demand-response). However, even small amounts of DR may provide large benefits to the system as a whole. Thus, even though DR market participants received subsidies, there are large positive externalities from DR (since prices are also lowered for those who do not curtail their demand). These positive externalities amount to a transfer of economic surplus from generators to those who do not curtail demand.

More generally, we can break down the economic effects of the PJM DR program into four components, which are explained below and shown graphically in Figure 4-3 (Brattle, 2007 and Boisvert and Neenan, 2003).

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[14] It is also possible that some of the response at low prices resulted from attempts at strategic bidding into the DR market by taking advantage of loopholes in the Customer Base Line (CBL) methodology used to determine the amount of load curtailments on a given day. PJM has recently taken steps to strengthen the CBL methodology to prevent such actions. The CBL methodology is outlined in PJM Manual 11 (PJM, 2008)

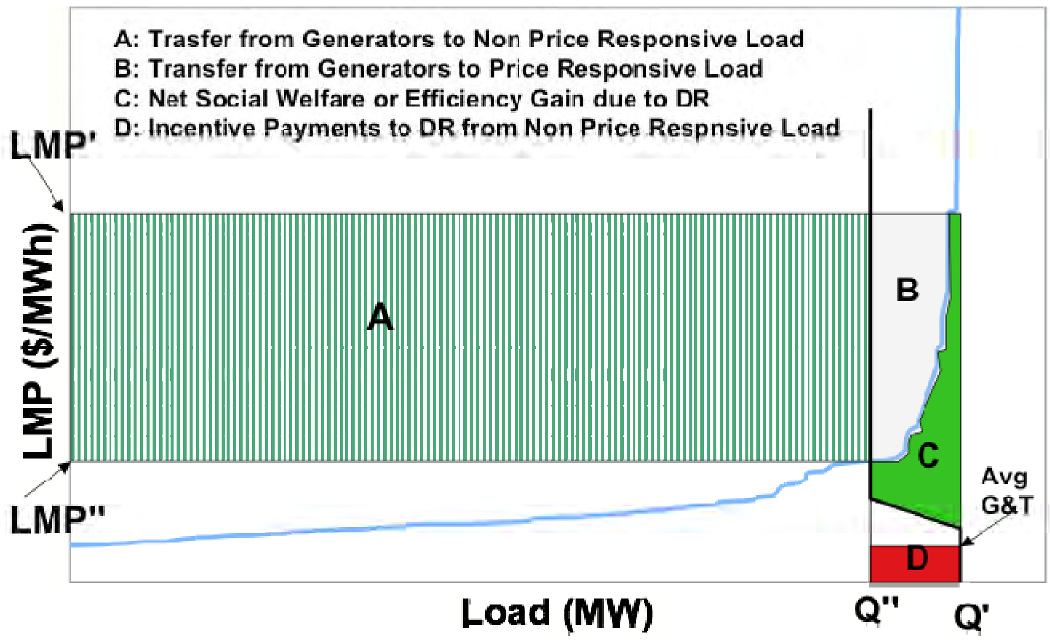

Figure 4-3: Conceptual framework for analysis of the PJM economic demand-response program.

The grey curve is the short-run marginal cost curve for electric generation. The black curve is the demand curve, with the sloped portion representing demand-response.

- ***Area A:*** A transfer of producer surplus (short-run profit) to consumers who do not curtail their demand. The term "transfer" is used here to indicate that the short-run profit lost by generators (due to the fact that DR causes prices to fall) is a direct benefit to consumers who do not curtail any demand, since they are able to enjoy their usual amount of electricity consumption at lower prices. The magnitude of the transfer is given by $Q" \times \Delta LMP(Q)$, where $Q"$ is the amount of demand in the system after DR market participants have curtailed their loads, and $\Delta LMP(Q)$ is the change in LMP resulting from $(Q' - Q")$ MW of demand being curtailed, that is, *∆LMP(Q) = LMP'–LMP"*. This transfer is area A in Figure 4-3.

- ***Area B:*** A transfer from generators to price-responsive consumers. This transfer is conceptually similar to the transfer in area A, but represents the benefit enjoyed by price-responsive customers due to lower energy prices. This transfer is equal to $(Q'-Q'')\times LMP'-\int_{Q''}^{Q'} MC(Q)dQ$, area B in Figure 4-3, where *MC(Q)* is the short-run marginal cost (MC) electric supply curve for the PJM market.

- ***Area C:*** A gain in social welfare (benefits that accrue to both consumers and generators) equal to $\int_{Q''}^{Q'} LMP(Q_s)dQ_s - \int_{Q''}^{Q'} LMP(Q_d)dQ_d$, where $LMP(Q_d)$ is the DR supply curve for those consumers participating in the DR market and $LMP(Q_s)$ is the LMP curve in the energy market. This social welfare gain is area C in Figure 4-3.

- ***Area D:*** An amount $(Q'-Q'')\times GT$, representing the subsidy payment. This represents a transfer from consumers who do not participate in the DR market to consumers who do participate in the DR market. Other things being equal, the subsidy payment persuaded some consumers who would not have participated with energy price signals alone to participate in the DR market.

Figure 4-3 illustrates that the DR program described here will convey a net social benefit if the social welfare gain is larger than the incentive payments (that is, if area C is larger than area D). Note that my analysis of the PJM DR incentive is somewhat different from the analysis described in (Boisvert and Neenan, 2003), which examined a DR program where the incentive payment is equal to $\int_{Q''}^{Q'} LMP(Q)dQ$, or the entire area under the price-responsive portion of the demand curve between *Q''* and *Q'* in Figure 4-3. My simulation procedure also differs from that of Brattle (2007), who use a proprietary market simulation tool to produce simulated prices with and without demand-response. The analysis in Figure 4-3 is a short-run welfare analysis and implicitly assumes that all participants in the DR market are small enough that individually they cannot influence the market-clearing price. The incentive payments given to DR market participants are funded by additional charges paid by load serving entities, based on their share of load in the zone where load is reduced. These fees likely introduce distortions and deadweight losses elsewhere in the market that are not captured in the partial equilibrium analysis presented here (although the total incentive payment is used as a proxy for these deadweight losses). Thus, my analysis likely overstates the net social benefits of PJM's DR program, though the deadweight losses not considered are likely to be small. Using the data shown in Figure 4-2, I estimate the sloped portion of the demand curve shown in Figure 4-3. Data released by PJM indicates that the maximum amount of participation in PJM's economic DR program in any given hour during the summer of 2006 was 325 MW. (Covino, 2006) Using these data, I calculated three DR supply curves, as shown in Figure 4-2. The curves are given by:

$$LMP''_t = 0.01 \times (Q'_t - Q''_t) + LMP^* \qquad (4\text{-}2)$$

$$LMP''_t = 0.15 \times (Q'_t - Q''_t) + LMP^* \qquad (4\text{-}3)$$

$$LMP''_t = 0.54 \times (Q'_t - Q''_t) + LMP^* \qquad (4\text{-}4)$$

The three different DR supply slopes were chosen to provide a sensitivity analysis to demonstrate the social welfare implications of a higher or lower price elasticity of demand. Participation in PJM's economic DR program amounted to only 0.2% of peak demand in 2006. In these simulations, I estimated the impact of DR representing up to 5% of peak demand, using the three slopes illustrated in Figure 4-2. This upper bound on DR was chosen to be consistent with assumptions used elsewhere in the literature (e.g., Boisvert and Neenan, 2003; Brattle, 2007), and allows us to calculate the net social benefits or costs of expanding PJM’s existing DR programs. Thus a maximum DR participation limit of 7500 MW was set (assuming a PJM peak load of 150,000 MW); this level of DR was attained only with most price-elastic DR supply curve (equation 4-2). Figure 4-3-a shows the 3 DR supply curves used for the sensitivity analysis.

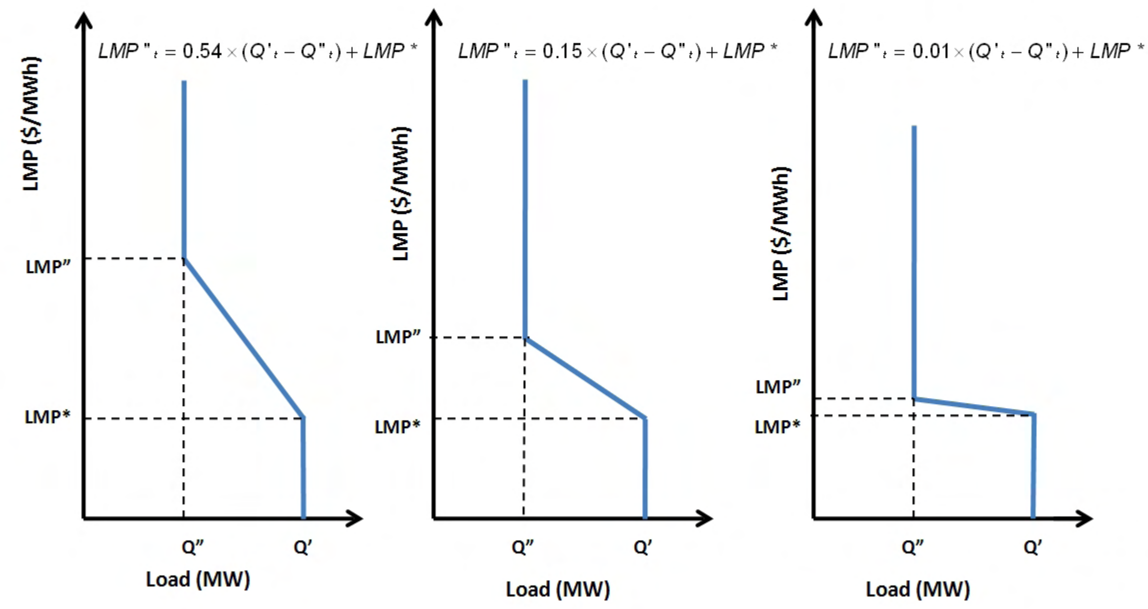

Figure 4-3-a: DR Supply curves used for sensitivity analysis

The DR supply curves used for this analysis divide the total demand into two parts: customers who can respond to price signal and customers whose demand is price inelastic. The inelastic demand is represented by the vertical part of the DR supply curve, whereas the price responsive load is represented by the sloped portion of the DR supply curve. The DR supply curve shown in Figure 4-3 and Figure 4-3-a is vertical on both ends of the DR slope. The vertical part of DR supply curve below the LMP* indicates that there is no DR participating in the market until the energy price exceeds LMP* due to the very small economic payoff as explained earlier. The DR supply curve then takes one of the 3 slopes discussed in Figure 4-2, until the maximum DR limit of 5% of peak load is reached (i.e. Q’ – Q” = 7500 MW). Once this limit is reached the DR supply curve is again represented by vertical line to represent the price inelastic load on the system.

4-4. Simulation procedure and estimated prices

For each hour of 2006, the actual load-duration curve and an econometric model of LMPs for the PJM market was used to estimate the four areas shown in Figure 4-3. Simulations were performed using each of the three DR supply curves shown in equations (4-2) – (4-4) as well as a number of different trigger points, LMP^*_j where j denotes the individual trigger point. The goal is to compare the social welfare gain from the DR program (area C) to the subsidy payment given to DR market participants (area D). My simulation procedure takes the following steps:

1. For each hour t, each DR supply-curve slope α_k, and each trigger point LMP^*_j the amount of DR in the market was calculated by solving equations (4-2) – (4-4) to get:

   $$(4\text{-}5)\quad DR_{t,j,k} = \begin{cases} \min\left((LMP''_t - LMP^*_j)/\alpha_k, 7500\right) & \text{if} \quad LMP''_t \geq LMP^*_j \\ 0 \quad \text{if} \quad LMP''_t < LMP^*_j, \end{cases}$$

   where $DR_{t,j,k}$ is the amount of demand-response that clears the market in hour t, with DR supply-curve slope α_k and trigger point LMP^*_j, and LMP''_t is the actual LMP in hour t. For hours where $LMP''_t < LMP^*_j$, demand-response is not profitable, so I assumed that $DR_{t,j,k}$ = 0 for those hours. For these simulations to be consistent with others in the literature, a ceiling was imposed on demand-response of 7500 MW for those hours where $LMP''_t \geq LMP^*_j$. 7500 MW is approximately 5% of the 2006 PJM peak system load. Table 4 shows the highest value of $DR_{t,j,k}$ that clears the market for each year, DR supply-curve slope α_k and trigger point LMP^*_j. In simulations I considered values for the slope of the demand-response supply curve α_k ={0.01, 0.15, 0.54} and value of the trigger point LMP^*_j ={$50, $60, $70, $75, $80, $90, $100}.

2. For each hour t, DR supply-curve slope α_k and trigger point LMP^*_j,:

(4-6) $$Q'_{t,j,k} = Q''_t + DR_{t,j,k}$$

where $Q'_{t,j,k}$ is the PJM system load in hour t, with DR supply-curve slope α_k and trigger point LMP^*_j in the absence of demand-response, and Q''_t is the actual PJM system load in hour t. That is, the amount of DR from step one is added to the actual PJM system load from hour t, yielding an estimate of what the system load would have been in the absence of demand-response.[15]

3. For each hour t, DR supply-curve slope α_k and trigger point LMP^*_j, calculate an estimate of what the LMP would have been in the absence of DR ($LMP'_{t,j,k}$) using a statistical model of LMP (Equation 4-7).

4. For each hour t, DR supply-curve slope α_k and trigger point LMP^*_j, calculate the areas of the four regions shown in Figure 4-3. Note that in steps one through four I have defined $Q''_{t,j,k}$, Q'_t, $LMP'_{t,j,k}$ and LMP''_t so as to be consistent with the nomenclature in Figure 4-3 and equations (2) through (4).

In step three of the simulation procedure, I employed a statistical model to estimate what the LMP would have been in the absence of demand-response. My model uses hourly demand and price data from the PJM real-time energy market in 2006. I model the hourly LMP in PJM as a sixth-degree polynomial function of load. Following Allen and Ilic (1999), I model the error term as following a first-order autoregressive process (AR(1) process). I also include fixed effects for each hour of the day, to capture variations between peak and off-peak periods. The model takes the form:

[15] Technically, I am interpreting Q'_t only as a base-case system load for the purposes of the simulation. I use actual hourly data from the PJM real-time energy market for Q''_t and LMP''_t. These data incorporate the amount of demand response that cleared the market in each hour at a trigger point of $75/MWh.

$$(4\text{-}7)\quad LMP_t = \alpha + \beta_1 Load_t + \beta_2 Load_t^2 + \beta_3 Load_t^3 + \beta_4 Load_t^4 + \beta_5 Load_t^5 + \beta_6 Load_t^6 + \varphi LMP_{t-1} + \Sigma_i \gamma_i Hour_{it} + \varepsilon_t,$$

where $Load_t$ is the real-time PJM load during hour t, LMP_{t-1} is the real-time LMP from the previous hour, the $Hour_{it}$ variables represent the time-of-day fixed effects, and ε_t is the AR(1) error term.

The estimated parameters of the model are shown in Table 4-3. All variables in the model were statistically significant at the 5% level. The R^2 of the model was 0.75, and the model's standard error is 306.2.

Table 4-3: Parameter Estimates from the Econometric LMP Model

Variable	Est. Parameter		T-Statistic
Constant	1,917.98	**	4.04
Load	-0.15	**	-4.35
Load^2	$< 10^{-21}$	**	4.65
Load^3	-7.55×10^{-11}	**	-4.97
Load^4	6.81×10^{-16}	**	5.31
Load^5	-3.21×10^{-21}	**	-5.67
Load^6	-6.18×10^{-11}	**	6.06
LMP(t-1)	0.68	**	121.63
Hour 1	2.75	**	2.97
Hour 2	5.72	**	6.12
Hour 3	4.30	**	4.57
Hour 4	5.20	**	5.51
Hour 5	7.69	**	8.17
Hour 6	12.34	**	13.29
Hour 7	20.04	**	21.80
Hour 8	9.64	**	10.48
Hour 9	9.64	**	10.48
Hour 10	11.15	**	12.10
Hour 11	12.04	**	13.06
Hour 12	8.31	**	9.00
Hour 13	9.09	**	9.86
Hour 14	10.33	**	11.20
Hour 15	7.69	**	8.33
Hour 16	7.93	**	8.60
Hour 17	12.74	**	13.81
Hour 18	14.00	**	15.14
Hour 19	5.43	**	5.85
Hour 20	6.61	**	7.14
Hour 21	11.06	**	11.94
Hour 22	1.91	*	2.07
Hour 23	-8.72	**	-9.45
AR(1)	0.03	**	3.97

R^2: 0.75
S.E.: 306.2
*Note: ** = statistically significant at the 1% level*
** = statistically significant at the 5% level*

4-5. Simulation results and discussion

Based on simulations, areas A through D were calculated for each hour of 2006. The annual total of each area's calculation for 2006 is shown graphically in Figure 4-4, for each assumed slope and each assumed trigger point. Summary data for the total amount of DR modeled is shown in Table 4-4, while the results of the welfare calculations are summarized in Table 5-5. Area B is omitted from Figure 4-4 since it is small compared to the others (Table 4-5).

The largest economic impact from PJM's DR market is a transfer of wealth from generators to those who do not participate in the DR program (area A in Figure 4-3). In 2006, I estimate the value of these transfers could have been between $18 million and $561 million, depending on the slope of the DR supply curve, and assuming a trigger point of $75/MWh. This wealth transfer increases as the trigger point decreases (since a lower trigger point can be expected to draw more DR into the market).

The simulations also indicate that the maximum amount of DR depends on both the slope of the DR supply curve and the incentive trigger point, LMP*. Table 4-4 shows the maximum amount of DR that can be cleared under different DR supply curves and different incentive trigger points. As expected, low trigger points and more elastic demand produce larger amounts of DR in the model.

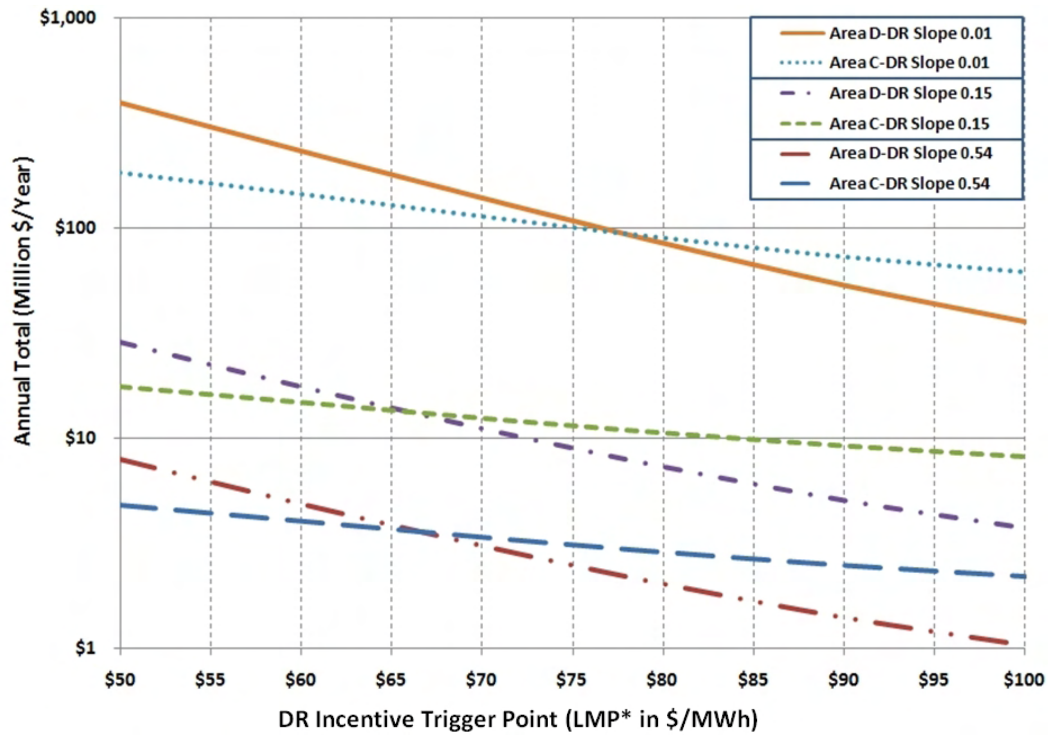

Figure 4-4: Effect of DR supply curve and LMP* on net social welfare and incentive payment (without considering scarcity pricing rules).

Figure 4-4 suggests a range for incentive trigger point at which the social welfare gain from DR (area C in Figure 4-3) outweighs the distortions due to the subsidy (area D) for different DR supply curves. In general, the annual subsidy payments tend to be greater than the net social benefit if the incentive trigger point is too low. This crossover point (where the social benefit is equal to the subsidy) occurs at a higher incentive trigger point for those DR supply curves that have lower slopes i.e. higher elasticity. The crossover point occurs at $66/MWh for the DR supply curve with a slope of -0.54. For the DR supply curve with slope of -0.01 the crossover point occurs at $77/MWh.

This analysis also indicates that with LMP* equal to $75/MWh (as in PJM's economic DR program as it existed prior to 2008), for the DR supply curve with a slope of -0.15, the estimate of the net social welfare gain exceeds the total subsidy payments by $2.6 million. For the same value of LMP* and the DR supply curve with a slope of -0.54, the estimate of the social welfare gain exceeds the total subsidy payments by $0.6 million. The subsidy payments exceed the estimated net social welfare by $7.2 million for the DR supply curve with slope of -0.01. Table 4-5 summarizes the effect of DR supply curve slopes and incentive trigger points on net social welfare, transfer payments from generators to load and subsidy payments to DR providers.

Table 4-4: Maximum amount of demand-response cleared based on different DR supply curves and DR incentive trigger points

	Maximum DR (MW) at various DR Incentive Trigger Points						
DR Slope	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
0.54	948.1	929.6	911.0	901.8	892.5	874.0	855.5
0.15	3413.1	3346.4	3279.8	3246.4	3213.1	3146.4	3079.8
0.01	7500.0	7500.0	7500.0	7500.0	7500.0	7500.0	7500.0

Tables 4-4 and 4-5 indicate that for a DR supply curve with a slope of -0.15 and LMP* equal to $75/MWh, the total transfer payments to load (areas A and B) during 2006 would be $70 million with a maximum of 3,246 MW of DR participating in the market. PJM (Ott, 2007) reports significantly larger energy payment reductions due to DR ($650 million during a one-week heat wave in August 2006), but their calculations likely differ from ours since PJM allows generators to charge above-market prices during periods when reliability may be threatened. The appendix 4-A-1 discusses the effect of including this "scarcity pricing" on the net social welfare and transfer payments. The amount of DR participation and associated economic welfare effects is also influenced by the shape of the price duration curve in any given year. Appendix 4-A-2 compares the results of analysis for year 2006 with the results for year 2005.

Table 4-5: Summary of effect of DR supply curve and LMP* on net social welfare, transfer payments and incentive payments (without considering scarcity pricing rules)

		Trigger Point LMP*						
	Area	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
DR Slope 0.54	**A**	$25.0	$21.6	$19.2	$18.3	$17.5	$16.1	$15.0
	B	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	C	$4.8	$4.0	$3.4	$3.1	$2.9	$2.5	$2.2
	D	$8.0	$4.9	$3.1	$2.5	$2.0	$1.4	$1.0
DR Slope 0.15	**A**	$95.2	$82.4	$73.5	$70.0	$67.0	$61.7	$57.3
	B	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4
	C	$17.7	$14.9	$12.5	$11.5	$10.6	$9.2	$8.1
	D	$28.6	$17.5	$11.1	$8.9	$7.3	$5.0	$3.7
DR Slope 0.01	**A**	$853.8	$698.8	$598.1	$561.2	$530.4	$483.8	$449.3
	B	$19.8	$16.6	$14.5	$13.8	$13.1	$12.1	$11.4
	C	$183.5	$145.4	$114.0	$101.2	$90.2	$73.4	$62.1
	D	$395.3	$232.8	$139.2	$108.4	$84.8	$53.4	$35.8

Note: All figures are in millions of dollars

4-6. Effect of the incentive structure on individual DR participants

Most of the DR participation in PJM's economic DR program is through curtailment service providers (CSPs), who act as DR aggregators, and facilitate DR participation in PJM's program. The principal service provided by these CSPs is to reduce the transactions costs (such as fees for market participation, gathering information and actually submitting bids) associated with participating in PJM’s DR market. Since increased participation in the PJM economic DR market improves social welfare for the system (as discussed above), the operating environment for CSPs becomes an important policy variable. In this section I extend the economic analysis of PJM’s DR programs to consider the participation incentives (that is, the revenue stream) for individual loads or load aggregators. Although an individual customer's decision to offer DR to the market is based on marginal revenue for a particular operating hour, CSPs must also evaluate the annual revenue potential for their own business model.

I calculate the maximum annual DR payment that could be earned by a DR participant in PJM using hourly LMP data from 2004 through 2007. I assume that each customer decides upon some "strike price" at which she is willing to participate in the DR market. The strike price is the offer price submitted by a DR market participant in the day ahead or real-time energy market. I do not attempt to explain the factors that might influence this strike price directly, but I note that since the strike price represents both the actual cost and opportunity cost of providing load curtailment, it will vary among individual DR participants and even among load aggregators.

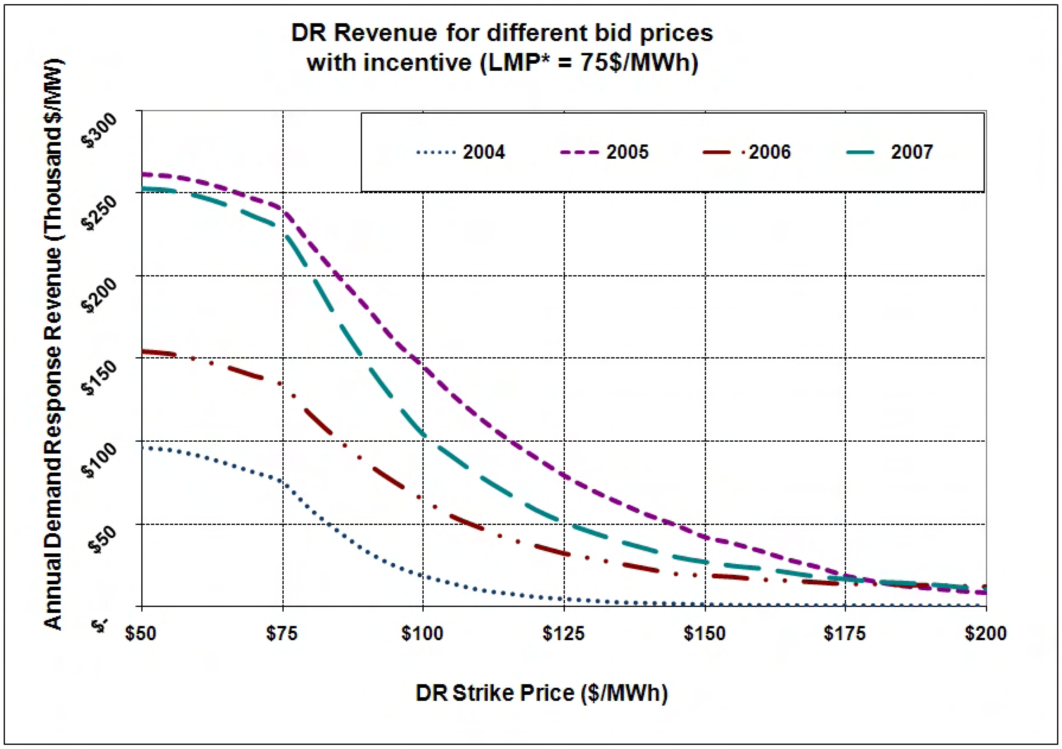

Figure 4-5: Expected real-time DR revenue with the incentive structure as it existed prior to 2008 (LMP* = 75 $/MWh).

Figure 4-5 shows a sensitivity analysis of the expected annual revenues during 2004-2007 from participating in the PJM economic DR market, as a function of an individual participant's strike price. As an illustration, in 2005 (the year with the most number of hours when the LMP was above any selected strike price in the sample) a customer with a strike price of $75/MWh would have earned approximately $240,000/MW; a customer with a strike price of $100/MWh would have earned $145,000/MW; a customer with a strike price of $150/MWh would have earned $42,000/MW; and a customer with a strike price of $200/MWh would have earned $8,000 /MW.

These estimates suggest upper limits for the gross revenues from DR program participation, assuming sufficient flexibility (that is, the customer can reduce demand during all hours in which the LMP exceeds her strike price). Note that I do not include any direct costs incurred through demand-response program participation (such as the costs of load curtailment, payments to

CSPs or the opportunity costs of time spent submitting bids and processing information), so these numbers should not be interpreted as profits or net benefits. A change in the incentive structure of the PJM economic DR program will affect the gross revenues from participation. This is shown in Figure 4-6 for the case of the subsidy payment being eliminated.

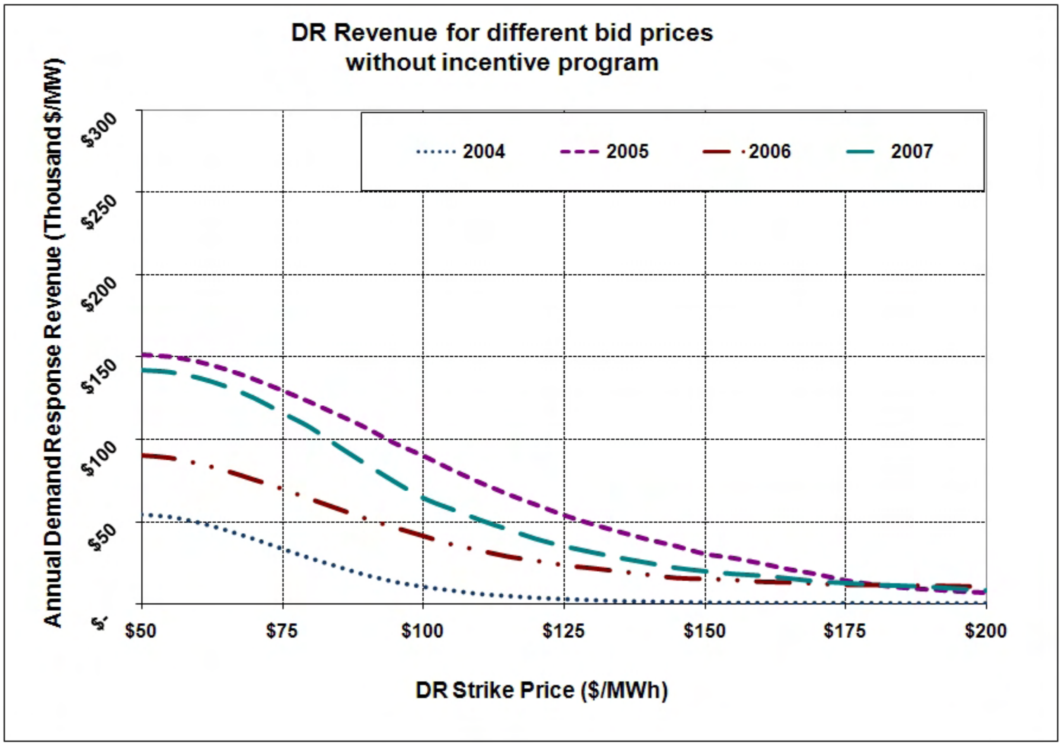

Figure 4-6: Expected real-time DR program revenue without incentive.

A customer who offers load curtailment with a strike price of $75/MWh would have received less than $130,000/MW in annual revenues in 2005 (without the subsidy payment) as compared to $240,000/MW under the original incentive structure as described in equation 4-1. The total revenue potential with and without incentive payments is summarized in Table 4-6. Note that some of the large jumps in gross benefits occur because the distribution of PJM LMPs is heavily skewed (prices in the PJM market get very high in only a small number of hours; in the short-run, this is a characteristic of most energy commodity markets), as shown in Figure 4-7.

Table 4-6: Change in annual DR revenue potential due to removal of incentive payments

Strike Price ($/MWh)	Revenues with incentive ($/MW-Year)			Revenues w/o incentive ($/MW-Year)			% Change		
	2004	2005	2006	2004	2005	2006	2004	2005	2006
$75	$74,833	$239,682	$133,755	$33,433	$129,682	$69,705	-55%	-46%	-48%
$100	$18,109	$145,244	$64,522	$10,209	$89,944	$40,972	-44%	-38%	-36%
$125	$4,164	$79,254	$31,851	$2,664	$53,704	$23,151	-36%	-32%	-27%
$150	$805	$41,925	$18,551	$555	$30,075	$14,751	-31%	-28%	-20%
$200	$-	$8,165	$11,661	$-	$6,315	$9,911	-	-23%	-15%

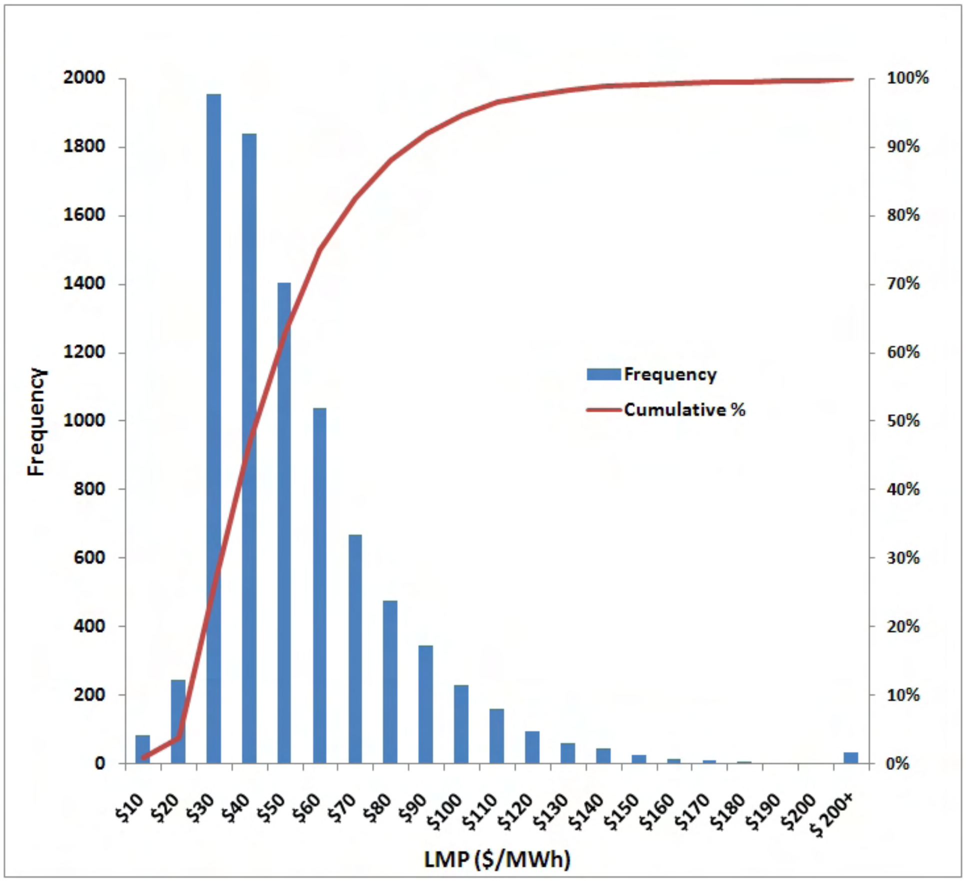

Figure 4-7: Histogram and cumulative distribution function of PJM LMPs in 2006.

With the subsidy payments for DR participation eliminated, some potential participants may increase their strike price so that the marginal payments from DR program participation are equalized with and without the incentive payment. For instance, customers with a G&T rate of $50/MWh may change their strike price from $75/MWh to $125/MWh after the subsidy is removed.[16]

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[16] Without the knowledge of each participant's marginal cost of providing DR, it is not clear that increasing the reservation price in this way represents an optimal strategy from a profit or utility-maximization perspective. Based on personal communications with participants in load curtailment programs, the strategy of increasing the reservation price does appear prevalent.

The annual revenues for an individual customer from demand-response participation will depend not only on the strike price and incentive structure, but also the distribution of market prices during any given year. I incorporated uncertainty due to fluctuations in energy prices from year to year into my analysis by performing a Monte Carlo simulation on the expected annual DR revenue stream, using LMP data from 2004 – 2007. I modeled annual revenues based on participant strike prices, with and without the DR market incentives. For each year t and strike price k, I assumed that annual revenues π_t follow a triangular distribution with the minimum value equal to the annual revenues in 2004 (the lowest revenue year in the sample), the maximum equal to the annual revenues in 2005 (the highest), and the most likely value equal to the average of the annual revenues during 2004-2007. I generated 1000 realizations of the discounted present value of expected annual revenues over a five-year time horizon, assuming a customer with an internal discount rate of 10%. Simulations were performed for a $75 strike price with the incentive as per equation 1, for a $75 strike price without the incentive and for a $125 strike price without the incentive (the latter two were done by setting $\pi_t = (LMP_t – GT)$ for LMP_t, ≥ strike price and zero for LMP_t < strike price).

These simulation results are shown in Figure 4-8. A demand-response market participant offering load curtailment at $75/MWh would receive a discounted gross revenue stream of $610,000 over five years with a 50% probability. On the other hand, if the incentive payment is removed, forcing the customer to adjust her strike price to $125/MWh (to receive the DR payment of $75/MWh), then the NPV would fall by roughly a factor of five, to $107,000.

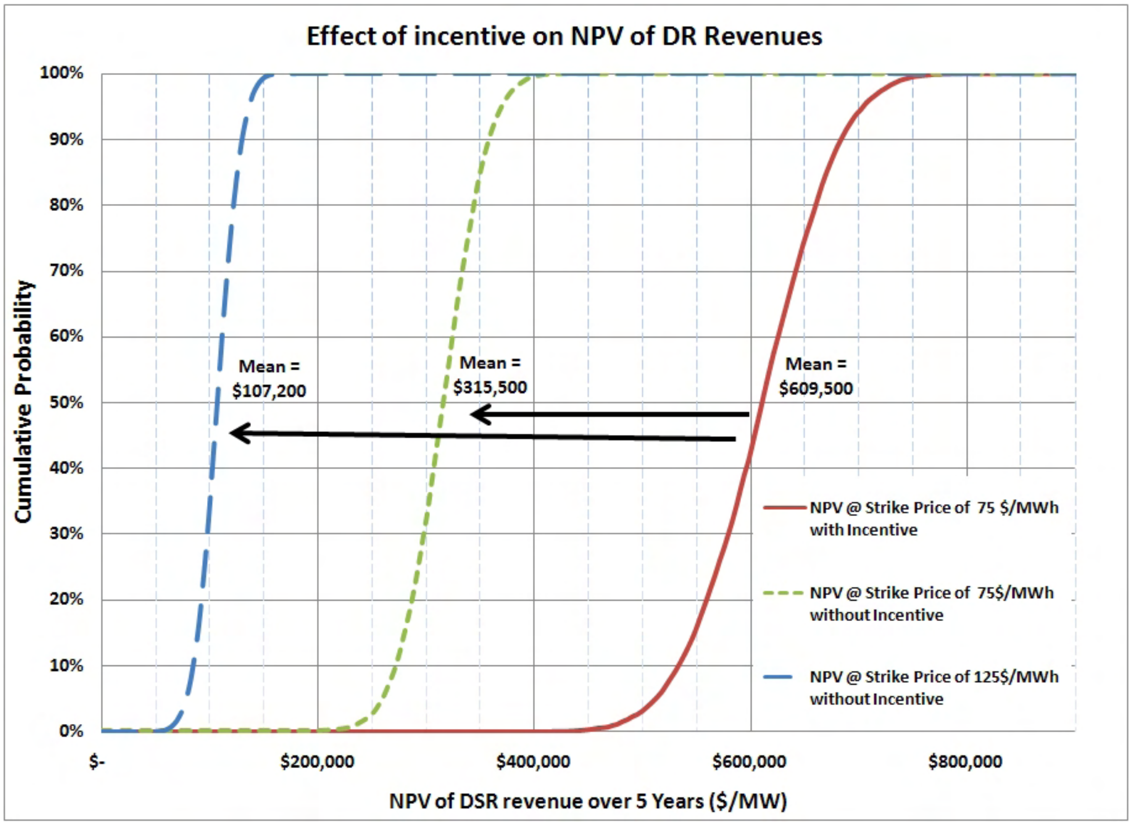

Figure 4-8: Cumulative probability of expected net present value of DR program revenue over 5 years under three incentive structures.

4-7. Conclusion

During peak periods, even very small decreases in demand can yield very large decreases in LMP. Since RTO markets in the U.S. are highly integrated and operate as uniform-price auctions, load curtailment by one party can provide large benefits (in the form of price reduction and perhaps increased reliability) to consumers who do not participate in RTO DR markets or are otherwise non price-responsive.

Centralized DR markets operated by RTOs often include subsidy payments to those who voluntarily curtail load, introducing market distortions associated with these incentives. I simulate load curtailment in the PJM market based on actual DR market result data under a number of different assumptions about the incentive program and the responsiveness of customers. I find that for recent levels of the incentive payment, the social welfare gains exceed the total annual subsidy payments. Thus, PJM's economic DR program as it existed prior to 2008 provided a net benefit to the system.

The subsidy payments in the PJM DR program acted to correct two market failures associated with the spot energy markets in RTOs. The first is the treatment of all demand as price-inelastic, which leads to deadweight losses in the market since resources (particularly during peak periods) are not dispatched in a way that equates marginal generator cost with marginal customer benefits. The second market failure is the temptation to free-ride in load curtailment. My simulations suggest that the wealth transfers associated with DR (particularly to non price-responsive load) are quite large compared to the gains to price-responsive load. The disparity between individual benefits and system benefits implies that, left to its own devices, the PJM energy market is likely to under-provide demand-response relative to the socially optimal point. The incentive payment provides a mechanism for correcting this externality. The subsidy paid to DR customers provides a mechanism to transfer part of the benefit received by non price responsive customers to price responsive customers responsible for achieving the benefits.

There are three primary factors that can influence the total quantity of DR in electricity markets.

- **Slope of DR supply curve:** The quantity of DR and the net social welfare impact is affected by the slope of the DR supply curve. Thus, the structure of a DR program can influence the program's outcome. For many customers, DR achieved through energy management and automated control systems can help to achieve load reduction goals at a reasonably low marginal cost as compared to load reduction through distributed generation (which potentially exposes customers to fuel price volatility). From the perspective of the system, both distributed generation and energy management can help achieve DR goals, but programs that can increase the price elasticity of demand will offer higher system-level benefits. This may require policies outside the electricity markets that can influence the integration of DR capabilities. Such policies could include new building codes and equipment standards, than encourage two-way communication to accept and respond to the price signal from grid.

- **Choice of incentive trigger point (LMP*):** The simulation results indicate that net social welfare would be increased if PJM reinstates the subsidy with LMP* between the range of $65 - $77. The LMP* may need to be changed based on changes in supply curve as well as level of DR participation in the market. The results of the simulation indicate that lowering LMP* can result in higher levels of DR participation for any given DR supply curve and a system SRMC curve.

  At the same time, caution should be exercised by avoiding the temptation of setting the LMP* too low, as it may result not only in subsidies out weighing net social welfare, but in extreme cases subsidies could be comparable to the size of transfers to non price responsive customers. (e.g. with a DR slope of 0.01, with LMP* setting of $50, subsidies would account for almost $400M out of the $850M transfers to non price responsive customers.) Also the PJM state of the market report for 2007 indicates that new base load generation units are not able to recover the capital cost in recent years based on energy revenues. Thus, increases in transfer payments from generators may result in a need to increase the capacity payments made to generators to overcome the shortfall in their energy revenues. When both these costs are combined (subsidy payments to DR customers and increased capacity payments to generators), the customers may not achieve significant savings.

- **Changes in the system short run marginal costs:** Potential changes in the SRMC curve due to increase in fuel prices or potential carbon tax, can result in greater opportunities for DR. If the SRMC curve shown in Figure 4-3 moves upward, then more DR can participate in a market for same level of LMP* and DR supply curve. Similarly reduction in the system reserves due to lack of new generation or growth in system load can result in more frequent use of scarcity pricing and thus result in higher savings due to DR than presented in table 4-5,

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Appendix 4-A-1. Effects of Scarcity Pricing

Starting in 2006, the Federal Energy Regulatory Commission (FERC) allowed PJM to permit generators to earn super-competitive rents (and thus avoid bid or price mitigation by market monitors) during periods where system reliability is threatened. The mechanism allowed by FERC for generators to capture these rents is known as "scarcity pricing." When scarcity pricing is triggered in a given region of PJM, the market-clearing price in the entire region will be set equal to the highest market-based offer price of *any* generating unit dispatched by PJM (PJM 2006). An overall cap on scarcity prices is set at $1000/MWh, but the rule does permit infra-marginal generators to earn higher profits than the energy market would normally allow.

Based on the price duration curve for 2006-2007 (Figure 4-1), I modified the model to simulate the effects of avoided scarcity pricing during the highest priced 15 hours. For these 15 hours, instead of using LMPs predicted by equation 7, market prices in the absence of DR were set equal to the scarcity price cap of $1000/MWh. These results, shown graphically in Figure 4-9 and summarized in Table 4-7, suggest that PJM's scarcity pricing provision lowers the incentive trigger point at which the social welfare gains from the PJM economic DR program equal the subsidy payments made under the program. For example, Figure 4-9 shows that when the effect of scarcity pricing is considered, the point where the social benefit is equal to the subsidy occurs at $51/MWh for a DR supply curve with a slope of -0.54. For the DR supply curve with a slope of -0.01 the crossover point occurs at $66/MWh. This represents a shift of -$11 to -$15/MWh from the model without scarcity pricing.[17]

[17] According to an internal cost benefit analysis performed by PJM staff the system wide benefits exceed the cost of DR program when the LMP* is set at $58/MWh for the day-ahead economic demand response program (FERC, 2007).

Table 4-7: Summary of effects of DR supply curve and LMP* on net social welfare, transfer payments and incentive payments (with scarcity pricing rules) for 2006

		Trigger Point LMP*						
	Area	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
DR Slope 0.54	**A**	$1,765.4	$1,762.3	$1,760.2	$1,759.5	$1,758.8	$1,757.8	$1,757.0
	B	$2.9	$2.8	$2.7	$2.6	$2.5	$2.4	$2.3
	C	$7.7	$6.8	$6.0	$5.7	$5.4	$4.9	$4.5
	D	$8.0	$4.9	$3.1	$2.5	$2.0	$1.4	$1.0
DR Slope 0.15	**A**	$1,804.3	$1,793.0	$1,785.5	$1,782.7	$1,780.3	$1,776.4	$1,773.3
	B	$10.6	$10.1	$9.7	$9.5	$9.2	$8.8	$8.3
	C	$27.7	$24.5	$21.7	$20.5	$19.4	$17.6	$16.1
	D	$28.6	$17.5	$11.1	$8.9	$7.3	$5.0	$3.7
DR Slope 0.01	**A**	$2,420.7	$2,265.8	$2,165.1	$2,128.3	$2,097.6	$2,051.2	$2,016.8
	B	$64.1	$61.0	$58.7	$57.7	*$56.9*	$55.5	$54.3
	C	$227.9	$189.7	$158.2	$145.2	$134.0	$116.7	$105.0
	D	$395.3	$232.8	$139.2	$108.4	$84.8	$53.4	$35.8

Note: All dollar figures are in millions.

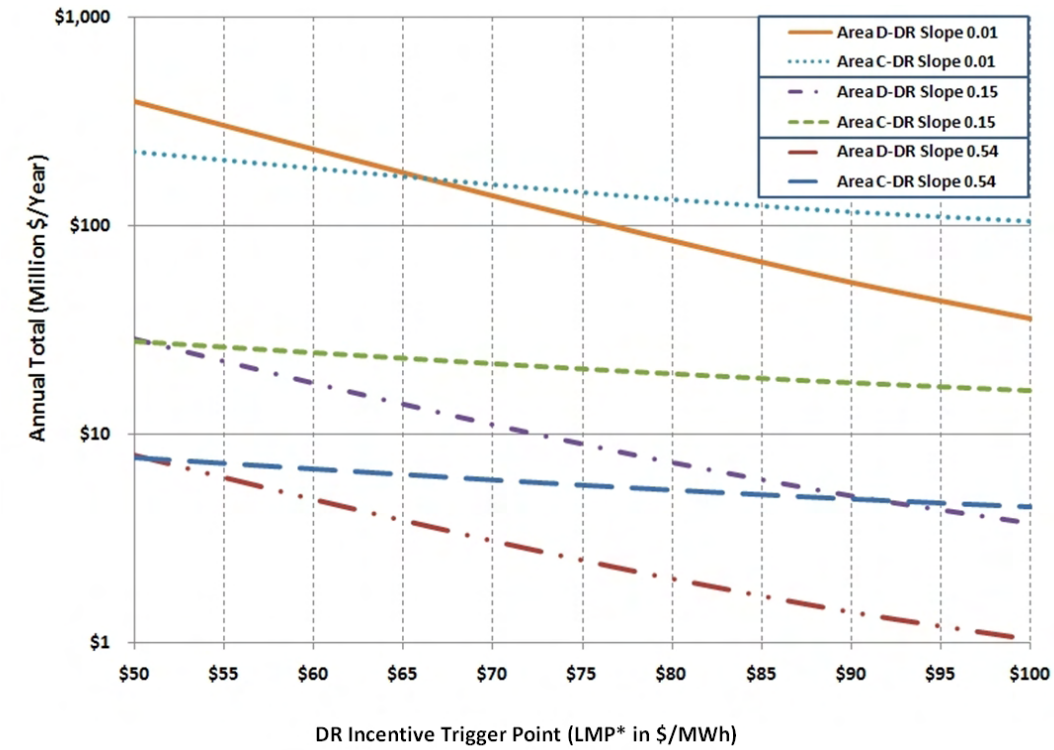

Figure 4-9: Effect of DR supply curve and LMP* on net social welfare and incentive payment (using PJM's scarcity pricing rules) for 2006.

Appendix 4-A-2. Effects of price duration curve

Since the amount of DR participation and associated economic welfare effects is also influenced by the shape of the price duration curve in any given year, I performed sensitivity analysis by performing the simulation described in section 4-4 with the PJM system load and LMP data for year 2005. Year 2005 had a distinctly different price duration curve than year 2006 as can be seen in Figure 4-1.

The peak load during year 2005 was only 134 GW as compared to 145 GW during year 2006. As a result there were no hours when LMPs went above $300 during year 2005, whereas there were 17 hours when LMPS went above $300 during year 2006. On the other hand, natural gas price increase in 2005 resulted in considerably higher number of hours when LMPs remained higher than $75/MWh (which was the trigger point for DR incentive as discussed before). Year 2005 had 2,200 hours when LMPs were above $ 75/MWh against 1,280 hours during year 2006.

Table 4-8: Summary of effects of DR supply curve and LMP* on net social welfare, transfer payments and incentive payments (without scarcity pricing rules) for 2005

		Trigger Point LMP* ($/MWh)						
	Area	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
DR Slope 0.54	**A**	$114.1	$111.0	$108.7	$107.7	$106.9	$105.5	$104.5
	B	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
	C	$5.1	$4.0	$3.1	$2.7	$2.3	$1.6	$1.1
	D	$10.5	$7.1	$4.8	$3.9	$3.1	$2.0	$1.2
DR Slope 0.15	**A**	$147.9	$136.6	$128.0	$124.5	$121.5	$116.5	$112.7
	B	$0.5	$0.4	$0.4	$0.3	$0.3	$0.3	$0.3
	C	$18.3	$14.6	$11.1	$9.6	$8.2	$5.9	$4.0
	D	$37.9	$25.7	$17.2	$13.9	$11.2	$7.1	$4.3
DR Slope 0.01	**A**	$853.3	$693.6	$568.7	$516.9	$470.7	$392.0	$325.5
	B	$21.2	$17.0	$13.9	$12.6	$11.4	$9.6	$7.9
	C	$269.2	$216.5	$167.6	$145.6	$125.4	$90.8	$63.5
	D	$550.4	$374.5	$251.0	$203.8	$164.3	$104.0	$63.4

Note: All dollar figures are in millions.

The effect of this pattern is reflected in the results of simulation summarized in Table 4-8 and Figure 4-10. The results indicate that for the simulation with data for year 2005, the optimal setting for LMP* would have been $100/MWh for the social benefit to equal the subsidy payments. The higher subsidy payments can be attributed to the higher number of hours when LMPs exceeded the LMP* during year 2005. Table 4-9 shows the numbers of hours when LMPs exceed the range of trigger points used in the simulation.

Table 4-9: Number of hours when LMPs exceeded the incentive trigger point (LMP*) during year 2005 and 2006

	Trigger Point LMP*						
Year	**$55/MWh**	**$60/MWh**	**$70/MWh**	**$75/MWh**	**$80/MWh**	**$90/MWh**	**$100/MWh**
2005	3,639	3,229	2,502	2,200	1,937	1,484	1,106
2006	2,650	2,195	1,526	1,281	1,050	703	471

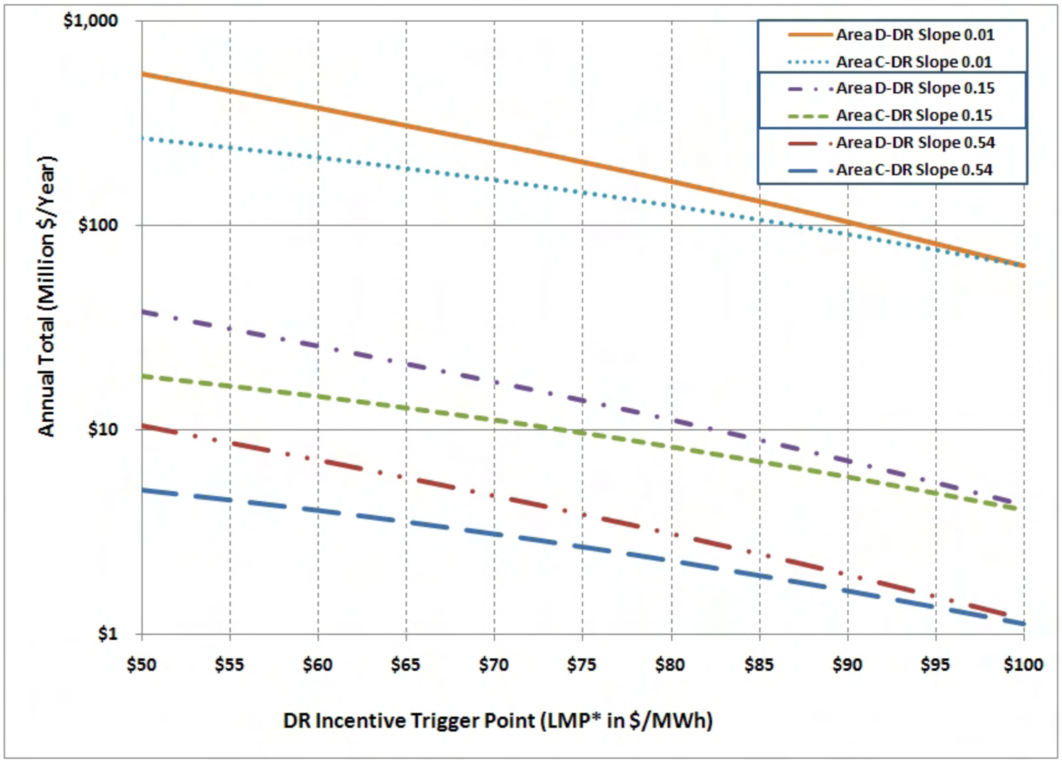

Figure 4-10: Effect of DR supply curve and LMP* on net social welfare and incentive payment for 2005.

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