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ARBITRAGE OPPORTUNITIES FOR ENERGY EFFICIENCY RESOURCES IN THE PJM CAPACITY MARKET

A Thesis in

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by

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Abstract

This study examines the effect of Energy Efficiency Projects on the Pennsylvania–New Jersey–Maryland Interconnection (PJM) Reliability Pricing Model (RPM). In particular, it focuses on the ability of Energy Efficiency (EE) resources to engage in arbitrage through bids into the RPM. There is currently no published research on the effect of this type of arbitrage behavior. This study provides the first analysis of capacity market arbitrage behavior by evaluating the market conditions necessary to engage in arbitrage and the implications that it has on market performance.

Two different models are used to analyze arbitrage opportunities within the bidding structure of PJM's RPM. A decision model, which assumes perfect information, and an option-based valuation model accounting for uncertainty are used to determine the conditions under which there is an incentive for parties to engage in arbitrage. Empirical sensitivity analysis is conducted using RPM auction data from PJM and building load data from the Philadelphia Navy Yard. Through this analysis, conditions are derived under which parties bidding energy efficiency capacity into the RPM have incentives to either follow through with investment in this capacity, or instead, to engage in arbitrage by covering their bid by purchasing lower priced capacity available in the short term market.

The results of the empirical analysis provide threshold values for capacity market auction prices, which determine whether or not owners of energy efficiency

resources would engage in arbitrage or follow through with an efficiency upgrade. The results of this analysis are very similar for both the recursive and perfect information models. For large commercial buildings with a peak demand of greater than 1 MW, the arbitrage strategy is profitable in expectation for the perfect information model when the total nominal capital investment cost is greater than 9.9 times the nominal annual energy savings resulting from that efficiency upgrade. Similarly, the decision to delay and engage in arbitrage will be made in the recursive game when the capital investment to annual energy savings ratio is greater than 8.8:1. For medium-sized commercial buildings with a peak demand between 0.25 and 1 MW, the arbitrage strategy is expected to be profitable, for the perfect information model, when the ratio of the total capital investment to annual energy savings is greater than 9.0:1 and is never used when this ratios is less than 8.6:1. For the recursive game, the decision to delay is made when the capital investment to annual energy savings ratio is greater than 8.6:1. For small commercial buildings, with a peak demand of less than 250 kw, the arbitrage strategy is expected to be profitable when the total capital investment to annual energy savings ratio is greater than 9.0:1 and will never be profitable when this ratio is less than 8.6:1. The decision to delay and engage in arbitrage will be made for the recursive model when this ratio is greater than 8.6:1.

In comparison with typical efficiency upgrades, there is a moderate potential for owners of energy efficiency resources to engage in arbitrage. Most efficiency projects have a total capital investment to annual energy savings ratio of about 4:1, however there are a large number of efficiency upgrades that are undertaken with a total capital investment to annual energy savings ratio between 5:1 and 10:1. Compared to a profitable capital investment to energy savings ratio of about 9:1 for arbitrage activity, there is significant opportunity for efficiency resource owners to engage in capacity market arbitrage.

I conclude that the arbitrage opportunity identified in this research may lead to market failures within the RPM if the bidding strategy is widely adopted by market participants. The cost of meeting installed capacity requirements may increase due to a potential shift from a three-year forward market to something closer to a spot market for capacity. In more extreme circumstances, this behavior may result in resource adequacy problems for PJM. As a result, it is recommended that PJM limit arbitrage activity by adopting policy changes to further regulate the bidding structure of the RPM.

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Chapter 1: Introduction

The issue of setting standards to ensure the provision of a sufficient supply of electricity is one of the largest topics of debate in energy policy today. This subject, generally referred to as resource adequacy, deals with the ability of the grid's generating capacity to adequately meet demand without incurring blackouts in times of very high load. The idea of resource adequacy standards comes from the notion that interruptions in the supply of electricity should be virtually nonexistent. The methods by which resource adequacy is achieved vary based on the regulatory regime that electricity production is subject to. Generally speaking, there are two such regulatory structures for electricity production, regulated and deregulated markets. [1]

In areas with regulated electricity markets, service is provided by a regulated utility. These areas are generally serviced by investor-owned utilities or publicly owned utilities with the exclusive right to a service area. Investor-owned utilities, which are private companies owned by shareholders, serve about seventy-five percent of electricity customers in the United States. These utilities are generally regulated at the state level, where public service commissions oversee investment decisions, operations, and rates. Publicly owned utilities, which include municipal utilities, government utilities, and rural electric cooperatives, are regulated municipal governments, coop boards, and federal regulators, respectively. [2]

In these markets, the relevant regulating authority sets resource adequacy requirements and oversees the investment in generation and transmission capacity. They also oversee utility operations, design price structures, and set price levels to allow utilities to recover required revenues (which are determined by the regulating agency). Resource planning is usually regulated through the requirement of Integrated Resource Planning (IRP). IRPs examine the forecasted load growth for a utility and determine the least cost resource mix necessary to meet the forecasted growth. The IRP is then used by regulating agencies to determine what investments utilities may make over time. [2]

Deregulated electricity markets are operated by Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs). RTOs and ISOs are very similar. These entities were established within deregulated markets to meet standards set forth by the Federal Energy Regulatory Commission. ISOs and RTOs plan and operate the electricity markets and transmission service in their respective service areas. In these areas, resource investment decisions are left up to private entities in an open, competitive market. [2] Suppliers build generation resources in response to their expectations about future prices in energy markets. [1] Generators then bid into energy and ancillary service markets and are dispatched by the ISO or RTO in the area. [2] While some generation resources are committed to providing ancillary services, a majority of the revenue stream for generators in deregulated markets comes from energy payments. As a result of this market-based investment structure, investor decisions may undershoot or overshoot the optimal level of resource investment, creating the need for a market mechanism to deal with supply shortfalls. A common policy solution is the implementation of a capacity market. [1]

Section 1.1: Capacity Market Overview

A capacity market provides payments to energy providers to maintain and invest in new capacity to deliver power to the grid at any given time. These markets are designed to ensure that there is proper resource adequacy in places where electricity deregulation has occurred. In deregulated electricity markets, market failures have led to the need for capacity markets to provide proper economic incentives for sufficient investment in generation capacity so that areas where deregulation has occurred have adequate resource reliability. [3]

There is an inherent inefficiency in competitive electricity markets that leads to the need for capacity markets. In a competitive (deregulated) electricity market, the marginal unit of production sets the price. When there is sufficient capacity to meet demand, suppliers earn the marginal cost of production for the highest cost resource. Prices may only reach levels above the marginal cost of the highest cost resource when there is resource scarcity. In the event of capacity scarcity, there is not sufficient generation available to meet demand at a price equal to the marginal cost of the last supplier. In this instance, the demand side must bid prices up until there is a market clearing equilibrium.

Figure 1 below depicts a scarcity event in which the demand side bids price up from the marginal cost of the last unit of production to a market clearing equilibrium. The black line represents the supply curve for two generators: a baseload plant and a peaking plant. The gold line represents the demand for electricity.

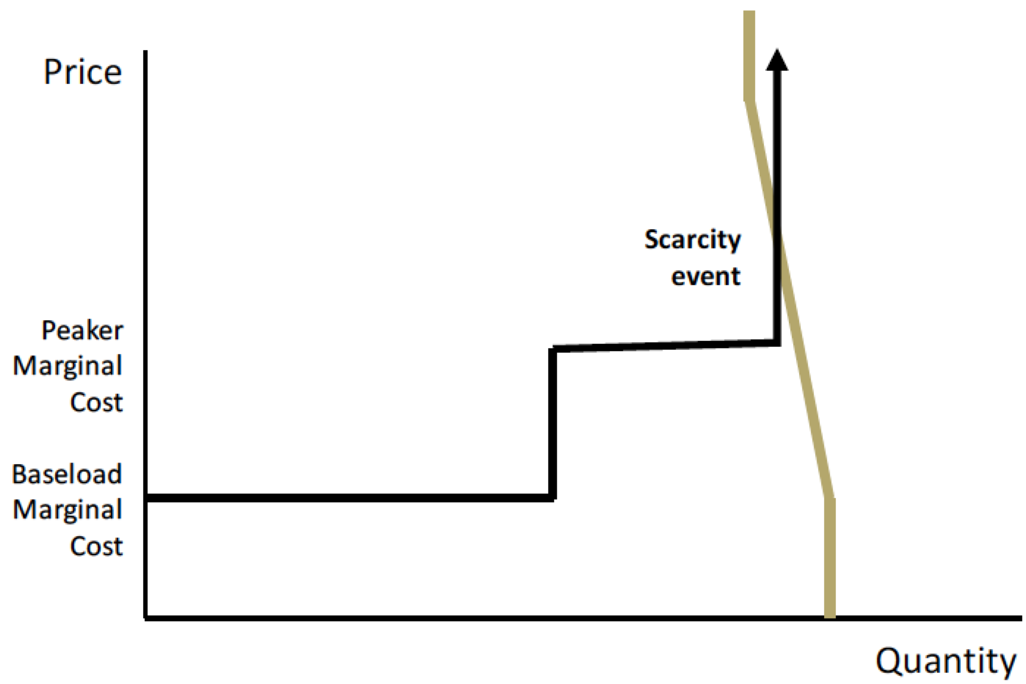

Figure 1: Scarcity Event [3]

In periods when there is no shortage of capacity, peaking resources can never earn revenues that surpass the marginal cost of producing an additional unit of electricity. This leaves them with unrecoverable sunk costs, typically capital investment costs. This market structure leaves no incentive to invest in new capacity resources when there is no scarcity of capacity. As a result, there is an inherent tendency to eventually produce resource scarcity. This is often referred to as the “missing money problem.” [3]

There are also price caps in ISOs, which, without proper capacity markets, will lead to resource shortages sooner or later. Although price-responsive demand is becoming more prevalent, the majority of demand remains inelastic with respect to wholesale electricity prices. Consumers of electricity generally pay an average price for electricity, and not the real-time wholesale price. Most consumers lack the real-time metering that is necessary to encourage price-elastic behavior. [3] Therefore they are naturally price-inelastic with respect to real time electricity prices and lack the ability to respond to changing electricity prices by adjusting consumption in the real time. If peak prices do not cause consumption adjustments in the real time, RTO's and ISO's may be forced to cut off power to some consumers without regards to their willingness to pay for power. As a result, customers with a high valuation of reliability may be blacked out while customers with a lower valuation for that power receive service. [3]

Figure 2 below displays this case, where rolling blackouts are caused by inelastic demand and resource shortages. The black line displays the supply curve for two types of generators, baseload plants and peaking plants. The gold line represents a price-inelastic demand curve.

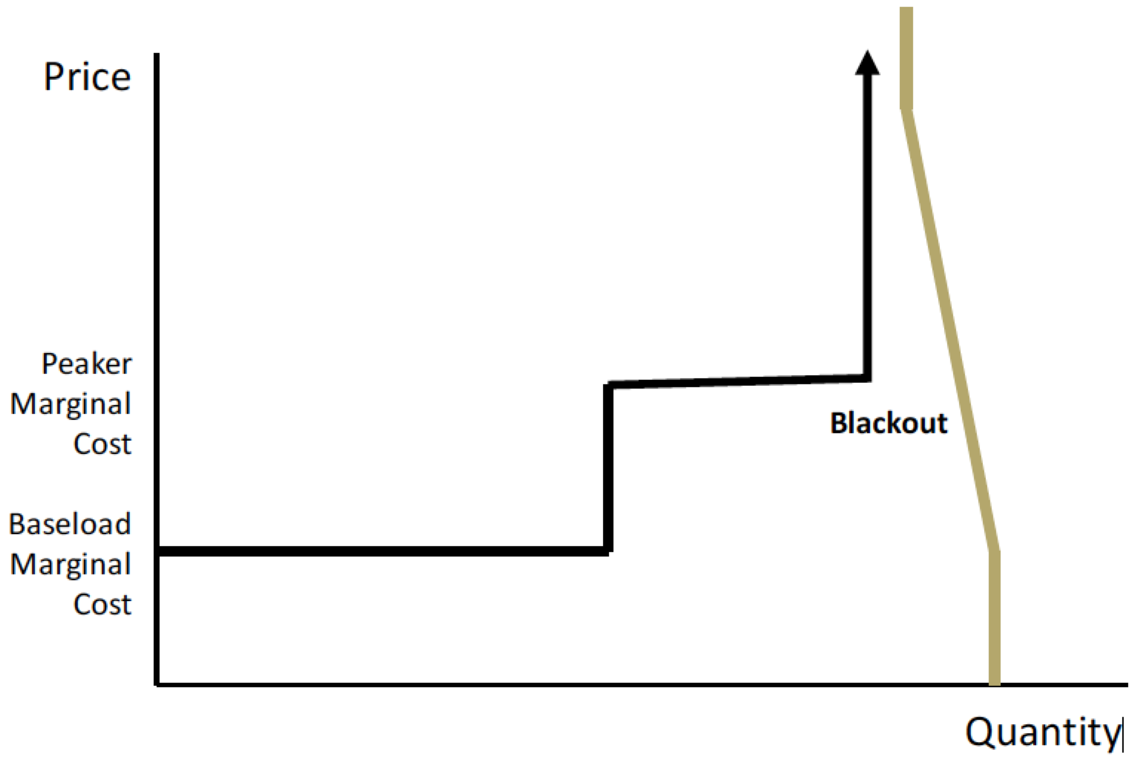

Figure 2: Resource Shortage Resulting in Blackout[3]

If there were enough demand side elasticity in the wholesale electricity markets, consumers would react to price signals and increase or reduce demand until there was a market clearing equilibrium. This would require extensive participation in demand response activities by consumers. Should demand for electricity truly become price elastic and demand response perforate the market, there may be no need for capacity markets to ensure resource adequacy. However, this would be contingent on prices being determined by the market, and at times, allowed to reach significantly high levels. Most RTO's and ISO's have instituted price caps in energy markets which, in instances of scarcity, prevent peaking plants from retrieving sufficient scarcity rents to incentivize investment in capacity. Furthermore, price caps in some instances of resource scarcity can prevent prices from getting high enough to reach a market clearing equilibrium. [3]

At this time, proponents of capacity markets argue that price caps and a lack of sufficient demand response necessitate the use of these markets to provide resource adequacy. These markets help mitigate the flaws inherent in a pure-market structure and provide the incentives necessary for new entry into competitive electricity markets. However, there is controversy surrounding the necessity and efficiency of capacity markets. Opponents to capacity markets argue that they are "mechanisms to transfer wealth to owners of otherwise uneconomic generation" [4] which burden ratepayers with substantial, unnecessary, charges. [4]

It is argued that the reasoning behind supply shortages and misallocations, which is based on the assumption that few consumers can respond to high prices by changing their consumption in the real time, is flawed. The increasing prevalence of demand response allows many consumers to view and respond to real time prices. Interruptible load programs are becoming more common in markets around the country, with some programs offering "ride through" tariffs that allow continuous service during an interruption for an increased premium. [4]

The issue of price caps causing a disincentive to invest in generation and failures to reach a market-clearing equilibrium may be addressed without capacity markets. The Electric Reliability Council of Texas (ERCOT) has raised it's price cap to

$9,000/MWh (compared to the cap of $1,000/MWh in PJM) in an effort to reduce the issues associated with lower price caps. [4]

Even the idea of the missing money problem, which may be the single most important argument in favor of capacity markets, is a contentious issue. Missing money models often assume that there are only two types of generators: baseload plants and peaking plants. In times of high demand, the baseload generators will earn market prices higher than their marginal cost of production, however, absent scarcity rents, peaking plants will never earn more than their marginal cost of production. In reality, there are many types of generators with varying marginal costs, providing RTO's with a convex bid-supply stack that slopes steeply up when loads are high. [4] This allows most peaking plants to earn profits in times of high demand, as the market price may be set by a higher cost generator. Furthermore, missing money models do not take ancillary service markets into account. Payments from ancillary service markets can allow generators to earn a profit when the market price for energy is not higher than their marginal cost of production. [4]

ERCOT's energy-only market serves as an example of an RTO that operates successfully without a capacity market. Although ERCOT operates without a capacity market, it has not experienced the investment shortfalls that have been associated with energy-only markets. With the exception of an unusually extreme capacity situation in 2012, ERCOT has met its resource adequacy targets every year. [4]

Section 1.2: Summary of the Reliability Pricing Model

In June of 2007, PJM introduced its new capacity market, the Reliability Pricing Market (RPM). Its previous capacity market, the Capacity Credit Market (CCM), was a voluntary mechanism through which LSE's could satisfy mandatory installed capacity obligations. The CCM was inefficient in its design and contracted a very small amount of capacity (less than ten percent of PJM's total capacity requirement). It failed to include explicit rules to mitigate market power, did not allow the participation of demand side resources, and yielded, on average, prices that were below the cost of adding new or maintaining existing capacity. The CCM also provided payments that were uniform across the RTO, failing to take into account the increased value of capacity in transmission-constrained areas. [5]

The RPM is based on annual auctions for the supply of electric capacity. These auctions are held in a bid auction style for locational capacity, in which supply offers are made for three-year forward capacity commitments (i.e., a commitment made during year *t* to have capacity available to produce electricity in year *t+3,* referred to as the "capacity delivery date"). PJM constructs a supply curve from the bids and clears this supply curve against a downward sloping demand curve to determine the auction-clearing price. The demand curve is administratively determined based on PJM's demand forecast for the deliverability year, so it may or may not reflect the "real" demand curve for capacity. Suppliers whose capacity offers clear the auction for delivery of a capacity resource in a given year receive payments equal to the auction-clearing price, on a per MW basis, every day for the duration of the delivery year. [5]

Under the RPM market design, Load Serving Entities (LSEs), generally wholesale electricity suppliers and electric utilities, must meet capacity obligations, referred to as Locational Reliability Charges. PJM procures capacity on behalf of the LSE's and charges them a daily Locational Reliability Charge based on the load that they serve. LSE's are not required to participate in the RPM auctions, however they may choose to "self-supply" resources to offset their reliability charges by directly offering resources into the RPM. [6]

Auctions are held on a locational basis within PJM due to transmission constraints. If there were no transmission constraints in the RTO, the RPM would yield one clearing price throughout all of PJM. In the presence of transmission constraints, the RPM is segmented on a locational basis to ensure that there is sufficient capacity located in transmission-constrained areas of PJM. PJM identifies transmission-congested locations as *Locational Deliverability Areas* (LDAs). These areas often have higher clearing prices than unconstrained areas within PJM to account for the added value of providing capacity in constrained areas. [5]

The RPM's main focus is to meet its installed capacity obligations. Therefore, the main purpose of capacity auctions is to purchase capacity that would otherwise not be supplied to the market or particular areas within the market. The capacity market occurs in four stages. There is an initial Base Residual Auction (BRA), which is designed to procure capacity required to meet the reliability requirements not met by the LSEs. Each of these BRA auctions is followed by up to three Incremental Auctions (IAs), occurring twenty-three months, thirteen months, and four months prior to the capacity delivery date. The incremental auctions occurring at twenty-three and four months prior to the delivery date allow suppliers to sell capacity that did not clear in the BRA or was not initially bid into the BRA. Suppliers may also purchase replacement capacity for supply bids that were entered into the BRA. Sometimes suppliers cannot meet the commitments tied to the bids that they initially entered in the BRA. Rather than facing fines for not providing the promised capacity resource, they can purchase capacity from another supplier who will then take on their capacity responsibilities. This allows them to essentially “buy out” of their original commitment at the clearing price of the incremental auction in which they participate, while still receiving the capacity payments from their original bid in the BRA. The Incremental auction that occurs thirteen months prior to the delivery date allows PJM to purchase excess capacity to meet its reserve requirements if load forecasts for the delivery year change. [5]

The PJM demand curve, which is determined based on a forecast of peak demand for each delivery year, is called the Variable Resource Requirement (VRR) curve. This downward sloping demand curve is designed to clear the auctions at a price higher than the Net Cost of New Entry (Net CONE) when the amount of reserve margin drops below what is needed to meet regional and local reliability requirements, offering incentive for new generation to be built. The Net Cost of New Entry refers to the cost of adding new capacity resources. Similarly the curve is designed such that when cleared capacity exceeds this target reserve margin, prices will fall below the Net CONE, giving a market signal that no new capacity should be pursued. Figure two below shows the VRR curve and the resulting clearing price. The Net CONE is the cost that a firm looking to enter the generation markets faces. In short, PJM attempts to design this demand curve to send a price signal to the market when new capacity in the region is needed. [5] Figure 3 below presents the VRR and Capacity Supply Curve in the 2011/12 BRA.

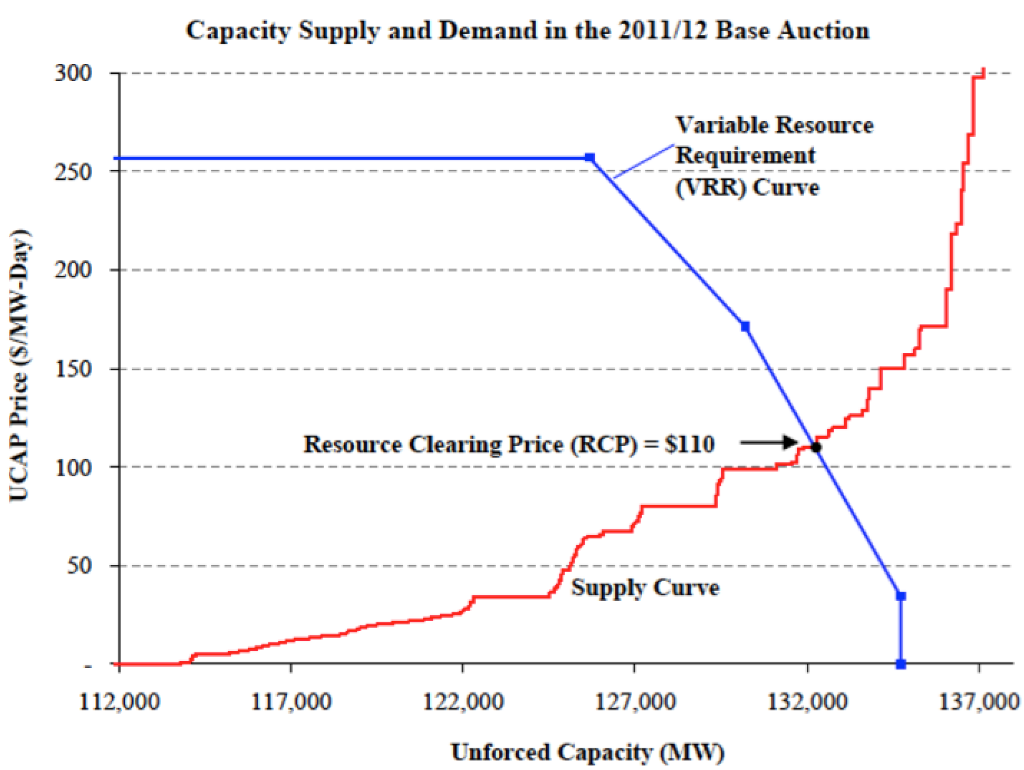

Figure 3: Capacity Supply and Demand in BRA [5]

PJM's RPM allows demand side resources to take part in capacity market auctions. [7] DR resources may also participate in energy market auctions as economic demand response. In this case, DR resources bid into the energy market and, if cleared, are paid LMP for their load reduction. [8]

Demand side resources have the overall effect of reducing the need for peaking capacity resources and lowering real time electricity prices in organized wholesale energy markets. [9] When electric demand is at peak levels, very expensive generating units, often referred to as peaking plants, must be used to meet demand. [8] Demand response resources reduce the load on the grid during peak hours and thus reduce the need to construct and use costly peaking resources. Furthermore, demand response serves to mitigate market power by providing more competition and thus reducing the tendency of generators to submit excessively high bids for fear of not getting scheduled. [12]

Research has shown that small load curtailments during times of peak demand can lead to significant reductions in price. A study conducted by PJM, which simulated the effect of demand side resources on wholesale energy prices, found that a three percent reduction in demand during the 100 highest-demand hours would result in a price reduction of between six and twelve percent. This would result in savings of nearly $300 Million per year within PJM. [9] A similar study conducted by the Brattle Group found that by curtailing three percent of peak load, energy savings in PJM could reach $36 Million per year, with benefits from reduced capacity requirements reaching nearly $75 Million per year. [13]

The economic effects of a price reduction in the energy market due to economic demand response may be broken down into four components. The first is a transfer of producer surplus to consumers that do not engage in demand response. This represents the benefit that consumers receive from a price decrease (as well as the producer surplus that is "lost" as a result of the lower price). The second effect is a transfer from generators to demand responders, representing the benefit to price responsive consumers from reducing load when prices are higher than their willingness to pay. The third is a gain in social welfare, which represents the benefits that exist for both producers and consumers. The final effect is a subsidy payment to demand responders that reduce load. This is the payment of LMP for real time load reductions. [8]

The following figure displays an example of demand response resulting in a price reduction in the energy market. In this example, price-responsive load is reduced from Q' to Q'', resulting in a reduction in price from LMP' to LMP." The shaded areas labeled A-D illustrate the economic effects of this price reduction that are described in the preceding paragraph. [8]

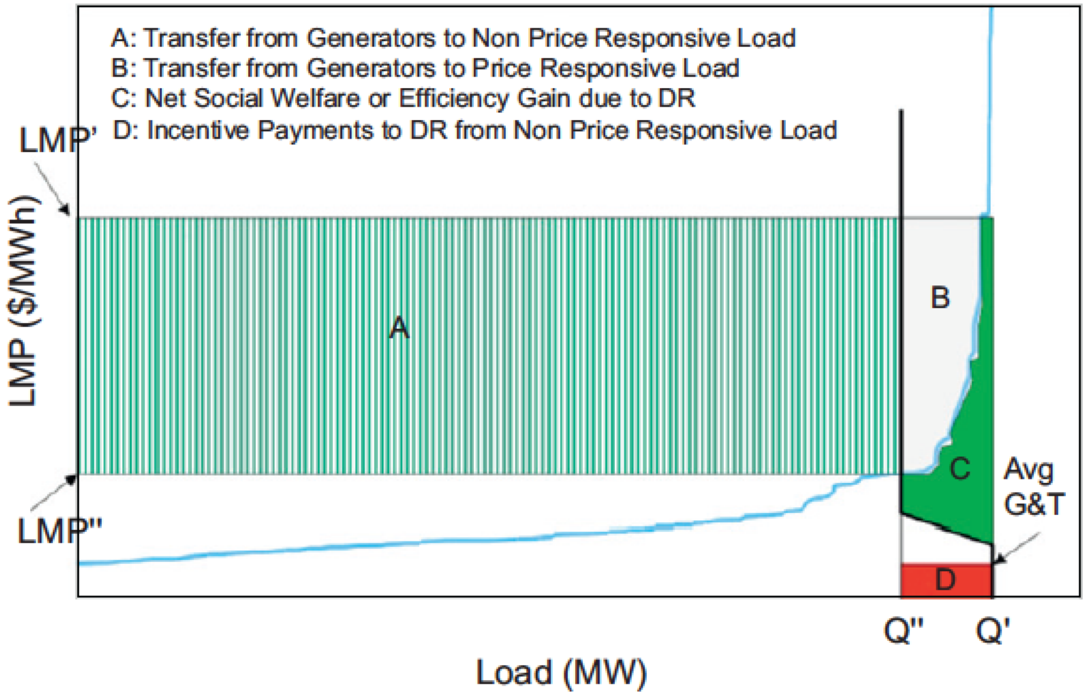

Figure 4: Economic Effect of Demand Response in Energy Market [8]

Different ISO's concentrate on different areas of demand response resources. PJM provides a majority of the dispatchable energy market demand response resources in the US, providing nearly fifty-five percent of this total. Furthermore, PJM was the first RTO to allow these demand resources to bid into its energy market and be dispatched like generation resources. ERCOT has enrolled over half of all the demand side resources participating in ancillary service markets. The Midwest Independent System Operator (MISO) has more than fifty-one percent of the capacity resources available from demand side resources. Only the New York Independent System Operator (NYISO) and Ontario's Independent Electricity System Operator (IESO) offer voluntary demand response programs in which demand side resources may voluntarily reduce demand to receive energy payments. [9]

Demand side resources may participate in PJM's RPM auctions as Limited, Extended Summer, or Annual Demand Resources (DR). [7] Energy Efficiency (EE) projects may also participate as capacity resources in the RPM for up to four years after completion of the project. These resources "generate" capacity by reducing the overall demand on the grid, therefore reducing the generation capacity necessary to fulfill reliability requirements. Capacity generated by Annual DR or EE resources is treated symmetrically to generating capacity in the PJM capacity market. [5]

The three types of DR capacity resources vary based on when, how frequently, and for how long they can be called on to reduce demand. Limited DR can be interrupted between 12:00 p.m. and 8:00 p.m. on non-holiday weekdays during June, July, August, and September. It may be called upon for a maximum of ten interruptions during this period per year, and may remain interrupted for up to six hours when called upon. Extended Summer DR is required to be available for interruption from 10:00 a.m. to 10:00 p.m. on any day between May and October. It may be interrupted for an unlimited number of times during this period and may remain interrupted for up to ten hours when called upon. Annual DR must be available any day of the year and may be called upon for an unlimited number of interruptions. It may be interrupted for up to ten hours per day during the hours of 10:00 a.m. to

10:00 p.m. in the May through October period and 6:00 a.m. to 9:00 p.m. during the November through April period. [10]

In order to resolve the operational constraints associated with the Limited and Extended summer DR products, PJM sets procurement targets in the RPM auctions for the different types of resources it requires to meet reliability goals. PJM identifies these as the Minimum Annual Resource Requirement and Minimum Extended Summer Resource Requirement. These requirements are set annually by PJM and determine the minimum amount of capacity that PJM seeks to procure from annual resources (generation, Annual DR, and EE) and Extended Summer resources (annual resources and Extended Summer DR). The Minimum Resource Requirements are set for the ISO as a whole, as well as for each LDA. As long as the RPM auctions produce more than these minimum requirements for Annual resources and a combination of Extended Summer and Annual resources, all resources accepted in the auction are treated identically and receive the same price. However, if either of the minimum requirements is not met, PJM will procure more Annual or Extended Summer resources, and less of the other resource types, in order to meet the requirements. In this case, PJM will pay a higher price to the unconstrained resources and a lower price to the limited resources. [10]

The amount of demand side resources offered into the RPM has been increasing since the creation of this market. Since the first auction, for the delivery year of 2008/2009, to the most recent auction, for the delivery year of 2014/2015, the amount of DR offered into the BRA has steadily increased from 715.8 MW to 15,545.6 MW. [11]

	RTO						
Auction Results (All Values In UCAP)	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015
Generation Offered	131164.8	132614.2	132124.8	136067.9	134873	147188.6	144108.8
DR Offered	715.8	936.8	967.9	1652.4	9847.6	12952.7	15545.6
EE Offered	0	0	0	0	652.7	756.8	831.9
Total Offered	131880.6	133551	133092.7	137720.3	145373.3	160898.1	160486.3
Generation Cleared	129061.4	131338.9	131251.5	130856.6	128527.4	142782	135034.2
DR Cleared	536.2	892.9	939	1364.9	7047.2	9281.9	14118.4
EE Cleared	0	0	0	0	568.9	679.4	822.1
Total Cleared	129597.6	132231.8	132190.5	132221.5	136143.5	152743.3	149974.7
Uncleared	2283	1319.2	902.2	5498.8	9229.8	8154.8	10511.6

Table 1: RPM Base Residual Auction Results [11]

Delivery Year	1st Incremental	2nd Incremental	3rd Incremental
2008/2009	-	-	1,032
2009/2010	-	-	1,798
2010/2011	-	-	1,845
2011/2012	361	-	1,557
2012/1013	1,749	3,214	4,382
2013/2014	4,882	5,598	-
2014/2015	6,849	-	-

Table 2: Incremental Auction Cleared Capacity (All Values in MW) [11]

This increase in the amount of DR offered into the BRA corresponds to a decrease in the clearing price of the BRA from $148.80 in the 2008/2009 auction, to $136.50 in the 2014/2015 auction. However, this does necessarily imply correlation between the change in clearing price and the change in the amount of DR offered, as clearing prices are dependent on many varying market conditions. Instead, clearing prices in each auction may be compared to the clearing price that would have occurred if DR offers were withheld. Monitoring Analytics conducted one such analysis, finding that market revenues would increase from $7,258,389,284 to $9,631,126,037 if non-annual demand side products (Limited and Extended Summer DR) were withheld from the auction. [7] This increase in market revenues, corresponding to a clearing price increase of about 33% compared to the actual auction results, implies that demand side resources, in particular Limited and Extended Summer DR, have the effect of significantly lowering RPM clearing prices.

Energy Efficiency resources have a similar ability to reduce energy and capacity prices through the reduction of demand. However, there has been a very limited amount of EE resources bid into the RPM to date, peaking at 831.9 MW of capacity bid into the 2014/2015 BRA. [11] As a result, the price-effect of EE resources has been limited. A reduction in supply of about 1000 MW in the 2014/2015 base residual auction that would occur if EE resources did not bid any capacity corresponds to an increase in the clearing price from $136.50/MW-day to $136.64/MW-day. This is equivalent to an increase in total market revenues by $17,717. An increase in the supply of EE resources of 1000 MW in the 2014/2014 BRA would result in a decrease in the market clearing price from $136.50/MW-day to $125.00/MW-day, corresponding to a savings of $1,711,701. [11]

In order to offer a Demand Resource or Energy Efficiency project into the RPM auctions, the resource being offered must be registered with PJM. In the case of a Demand Resource, the resource must be in a party's portfolio for the delivery year at hand. To add a new resource to a portfolio or update an existing resource, the resource provider must complete a Demand Resource Modification (DR MOD) transaction. This is used by PJM to track increases or decreases in the nominated value of the DR Resource in a party's portfolio. DR MODs will be "provisionally approved" only after PJM has reviewed a submitted timeline and milestone projection to ensure that the DR Resource will be available by the start of the delivery year. Only DR MODs that are in the "provisionally approved" or "approved" status will be considered in a party's "Demand Resource Position," and thus available for RPM auctions. [6]

In the case of Energy Efficiency offerings, projects must meet a number of criteria in order to be eligible to participate in RPM auctions. The project installation must be scheduled for completion prior to June of the delivery year and the installation must not be reflected in the peak load forecast posted for the BRA of the initial delivery year (this is only a concern for projects completed prior to 2011). The resource provider must also submit an Initial Measurement and Verification Plan no later than 30 days prior to the initial RPM Auction in which the resource is offered, as well as an Energy Efficiency Resource Modification (EE MOD). [6] The Measurement and Verification Plan (M&V Plan) must include the nominated value (amount of capacity) of the EE Resource, a summary of the methodologies used to determine the nominated EE Value, a description of any variables that affect the project's electrical demand that will be used in the determination of the Nominated EE Value during performance hours, and all assumptions for the Nominated EE Value, including baseline demand, post-installation demand, process changes, and project lifetime. The report must also include specifications of equipment being used for installed projects, including engineering analysis used to specify equipment, program design measures, and applications of all equipment. [14] The EE MOD is similar to the DR MOD and must be completed prior to bidding the resource into the RPM. PJM will provisionally approve an EE mod once it has approved the Initial M&V Plan. [6]

Unlike DR and EE resources, which only have to submit a plan to bring the resource online by the delivery year in order to participate in the RPM, planned generation resources have more stringent requirements. Prior to participating in any RPM auction, generators must execute an interconnection agreement with the transmission owner to whose transmission and distribution system the resource will be connected. This agreement must include a System Impact Study Agreement and an Interconnection Service Agreement. PJM must review and approve the interconnection agreement before a planned generation resource may participate in the RPM auctions. [15] It can be assumed that this contrast in review requirements between generation and demand side resources results in lower fixed costs for demand side resources as compared to generation, and thus allows for more flexible bidding strategies for EE and DR resources.

The *2012 State of the Market Report for PJM* identifies that some demand side resources have been bidding capacity into the BRA and using one of the IA's to sequentially buy out of their commitment. [14] This behavior may produce a profit without any implementation of the demand side resources originally promised. As a result, parties are effectively engaging in arbitrage within the RPM. Presently, no analysis on the implications of this behavior has been published.

Chapter 2: Research Contributions

There has been considerable research done on the subject of Demand Response resources. These resources have been evaluated with respect to market performance and efficiency within energy and capacity markets. Demand Response resources have been compared to generation in many studies, which have evaluated whether Demand Side resources should be treated symmetrically to generation. Many studies have been conducted to determine the effect that Demand Side Resources have on energy, capacity, and ancillary service markets. Although there is still much debate among industry experts as to how demand side resources affect the overall performance of these electricity markets, the subject has been widely studied.

Energy Efficiency resources, however, have not been studied at great length. There is limited information on the effect that Energy Efficiency upgrades have on electricity markets. Participation by Energy Efficiency resources in the PJM capacity market is relatively new. As a result the implications of Energy Efficiency bids into the capacity market are yet unknown.

This thesis seeks to evaluate the effect of Energy Efficiency projects on the PJM Reliability Pricing Model. In particular, it focuses on the historical ability of Energy Efficiency resources to bid capacity into the BRA and then buy out of their commitment by purchasing replacement capacity in one of the Incremental Auctions at a lower price without ever making an efficiency upgrade, effectively engaging in arbitrage. A few instances of this behavior by Demand Response resources have been documented by PJM. [8] However, no analysis on the implications of this behavior has ever been published. This thesis provides an in depth analysis of the conditions under which Energy Efficiency resources have the incentive to delay investment in Energy Efficiency upgrades and engage in this arbitrage behavior in the RPM. It's concluded that the arbitrage behavior is a profitable strategy when the capital investment required to complete the efficiency upgrade is more than three times greater than the annual energy savings that would result from that project. It is also concluded that, if this strategy is widely adopted by market participants, it may lead to market inefficiencies.

Chapter 3: Arbitrage Decision Model

The current PJM capacity market design provides participants with the opportunity to engage in arbitrage between the BRA and Incremental Auctions. Since the development of the RPM auctions, IA prices have generally been lower than BRA prices. One possible explanation for this pattern in auction prices is that PJM consistently over-forecasts the demand profile each year, leading to a high BRA price. The data for this analysis was gathered from the PJM "Market and Operations" publicly available auction results.

Delivery Year	BRA	1st Incremental	2nd Incremental	3rd Incremental
2008/2009	$148.80			$10.00
2009/2010	$191.32			$86.00
2010/2011	$174.29			$50.00
2011/2012	$110.04	$55.00		$5.00
2012/1013	$139.73	$153.67	$48.91	$2.51
2013/2014	$245.00	$178.85	$40.00	
2014/2015	$136.50	$16.56		

Table 3: RPM auction results since the 2008 delivery year [16]

The arbitrage referred to in the following models is an example of "speculative arbitrage." Generally, arbitrage is thought of as the ability to make a profit through financial transactions that take advantage of a price discrepancy in two related markets without incurring any costs or risk. In reality, though, many arbitrage opportunities have some risk of a loss associated with them. These opportunities are referred to as "speculative arbitrage." For the purpose of this paper, I will be referring to speculative arbitrage when I use the word "arbitrage." [17]

The arbitrage strategy that is modeled consists of bidding an Energy Efficiency capacity commitment into the Base Residual Auction and subsequently buying out of that capacity commitment in one of the Incremental Auctions, much like closing out an option. Energy efficiency projects "generate" capacity by lowering the overall demand on the grid. A party considering undertaking an investment to make an energy efficiency upgrade to a building can bid the capacity of the upgrade into the RPM in the BRA. The party may then "close out the option" by buying out of its capacity commitment in one of the incremental auctions. Seeing as the RPM auctions are three-year forward auctions, one could essentially bid the energy efficiency capacity into the BRA and proceed to buy-out of the obligation in one of the IAs without ever making any investment. PJM does not assess any penalties on participants who buy-out of their capacity obligations because the capacity commitment will be met when the "option" is closed out. This strategy could be continued as an infinite game, each year bidding capacity into the BRA and buying out of the capacity commitment in one of the incremental auctions.

While this analysis is specific to EE capacity bids, the same strategy could be applied to Demand Response programs as well. Generators could engage in the same behavior, however, unlike EE and Demand Response, they would have already incurred significant fixed costs. PJM only requires a plan to complete the EE upgrade or measure the DR capabilities. However, generators must have completed a system impact study and signed an interconnection service agreement. Thus generators would rationally bid their capacity into the BRA without the execution of the arbitrage strategy (as the arbitrage strategy would yield payments that are lower than if one were to simply bid into the BRA and fulfill their commitment).

The following models present the payoffs from engaging in arbitrage or investing in the efficiency upgrade. The model in section 3.1 is a decision model that outlines the conditions under which one would engage in arbitrage or complete the efficiency upgrade. This model assumes perfect information for the decision maker with respect to the RPM auction prices for the duration of the game. The model in section 3.2 uses an option-value framework to value the option to engage in arbitrage under imperfect information with respect to the RPM auction prices.

Section 3.1: Arbitrage Game with Perfect Information

The following mathematical model uses an NPV valuation approach to determine the conditions under which this "continuous arbitrage game," where a party continuously bids an EE upgrade into the BRA and then buys out of their commitment, is a profitable economic strategy. This game represents a player's decision to invest in the efficiency upgrade or engage in arbitrage when they have perfect information about future prices in the base residual and incremental RPM auctions. In this "arbitrage game," the party bids an EE project into the capacity market at time i (to be delivered at time i+3). Then, at time $i+1$, the party buys out of its obligation in the IA. At time $i+1$, it also bids in the same EE project (for delivery at time i+4), and again buys out of its commitment in the subsequent IA (this time at time i+2). The EE project is rebid into the RPM in this fashion continuously until time *j*. At time *j*, the party makes the decision to complete the EE upgrade and undertakes the necessary capital investment for delivery in year j+3. The model also evaluates the conditions under which the party would be better off by making the efficiency investment, reaping the energy savings, and bidding their capacity into the BRA for the 4 years that PJM allows EE to receive capacity payments.

This model is based on a number of assumptions. First, it assumes that there are no operating expenditures associated with EE projects, and that the only relevant cost is the capital investment necessary to complete the project. It is also assumed that the capital investment cost is incurred over one year and occurs one year prior to the delivery date. Each EE project is assumed to reduce building electricity demand by thirty percent, which is the reduction target for the Energy Efficient Buildings Hub in Philadelphia. This allows energy savings to be calculated for any given building size.

The model uses the following variables:

S - Net Energy Savings from the EE upgrade ($)

C – Annual capital investment cost needed to complete EE upgrade ($)

B – Building size scaling factor set to thirty percent of peak building demand (MW)

P_{BRA} – BRA auction price ($/MW-day)

P_{IA} – Incremental auction price ($/MW-day)

n – Lifetime of the energy savings from the EE project (Years)

j – Year at which to make capital investment in efficiency project (Years)

i – Present year (Years)

t – Time (Years)

r – Interest rate

δ - Discount factor

The interest rate is set at r = 0.05. This determines the discount factor to be $\delta = 0.952$, as $\delta = \frac{1}{1+.05} = 0.952$. Time i, the present year, is set to $i = 1$. The lifetime of the energy savings is set to n = 50.

I begin with a model for the NPV of investing in an energy efficiency project that includes payments through the RPM. I refer to this model as the "baseline model." The first term in equation (1) represents the capital expenditure an investor would have to undertake, starting in year i+2 and assuming completion of the project at year i+3. The project will be bid into the three-year forward RPM auctions in years i through i+3, as Energy Efficiency projects can be bid into the RPM (and thus receive capacity payments) for a maximum of four years. The coefficient of 365B, which scales the RPM payment by the building size and accounts for the 365 daily payments each year, standardizes the units to dollars. This explains the second term, which accounts for the payments from the RPM for four years, starting in year i+3 and ending in year i+6. The final term represents the summation of all of the energy savings, across the lifespan of the project. Again, it begins in year i+3 because I assume completion of the project in this year. The discount factor, δ^{i-1}, discounts everything back to the time when the project begins (year i), accounting for the time value of money, and thus providing the net present value of the project in year i.

The RPM prices are in \$/MW/day, so the 30% load reduction is multiplied by the Auction prices, converting them into units of \$/day. Since one period in this case is one year, this number is again multiplied by 365 days to get the number into units of dollars so that we can sum the annual revenue from auction payments, capital costs (C), and nominal energy savings (S) in consistent units. Thus, every P_{BRA} and P_{IA} term is scaled by a factor of 365B, where B represents 30% of peak load.

$$(1) \qquad NPV_{EE\ Project} = \sum_{i+2}^{i+2}(-C)\delta^{i-1} + 365B\sum_{i+3}^{i+6}\left(P_{BRA_i}\right)\delta^{i-1} + \sum_{i+3}^{n+3}(S)\,\delta^{i-1}$$

Equation (2) displays the model for the "arbitrage game" scenario. This model represents the decision to delay investment in the efficiency upgrade for one period in order to engage in arbitrage. This model begins at the same time (time i) as the baseline model. At time i, the party bids the EE upgrade into the BRA for delivery at year i+3. At time i+1, the party then buys out of their capacity commitment in the IA and rebids this capacity into the BRA for delivery at time i+4. At time i+1, the party commits to completing the EE upgrade and invests in the project, incurring capital expenditures (-C) in years i+1, i+2, and i+3. The party receives energy savings for the span of the project, beginning in year i+4. The first term in this model accounts for the "arbitrage payment" for one period. The rest of the model is the same as the baseline model, discounted by one period to account for the delay in investment.

$$(2)\qquad NPV_{Arbitrage} = 365B\sum_{i+3}^{i+3}\left(P_{BRA_i} - P_{IA_i}\right)\delta^{i-1} + \sum_{i+3}^{i+3}(-C)\,\delta^{i-1}$$

$$+365B\sum_{i+4}^{i+7}\left(P_{BRA_j}\right)\delta^{i-1} + \sum_{i+4}^{n+4}(S)\delta^{i-1}$$

Equation (3) represents the continuous arbitrage game, in which a party delays investment in the efficiency upgrade until time j by continuously buying out of their capacity commitment. This is similar to the one period arbitrage model in equation (2), but it accounts for arbitrage payments in years i+3 through j+3 and heavier discounting of all terms as a result of the continuous delay of the investment.

$$(3)\qquad NPV_{Arbitrage} = 365B\sum_{i+3}^{j+3}\left(P_{BRA_i} - P_{IA_i}\right)\delta^{i-1} + \sum_{j+2}^{j+2}(-C)\,\delta^{j-1}$$

$$+365B\sum_{j+3}^{j+6}\left(P_{BRA_j}\right)\delta^{j-1} + \sum_{j+3}^{j+n+3}(S)\delta^{j-1}$$

The EE project owner is indifferent between investing in the project at time i, and playing the arbitrage game until time j, if the following condition holds:

$$(4)\qquad 365B\sum_{i+3}^{j+3}\left(P_{BRA_i} - P_{IA_i}\right)\delta^{i-1} + \sum_{j+3}^{j+3}(-C)\,\delta^{j-1} + 365B\sum_{j+3}^{j+6}\left(P_{BRA_j}\right)\delta^{t-1}$$

$$+\sum_{j+4}^{j+n+4}(S)\delta^{t-1}=\sum_{i+2}^{i+2}(-C)\delta^{t-1}+365B\sum_{i+3}^{i+6}\left(P_{BRA_i}\right)\delta^{t-1}+\sum_{i+3}^{n+3}(S)\,\delta^{t-1}$$

This condition is achieved by equating (1) and (2). By setting these equations equal to one another, we can solve for conditions under which one would be indifferent between investing at time i and playing the arbitrage game until time j. If this is instead set as an inequality, the equation can be solved for conditions under which the project owner would invest at time i, choosing not to play the arbitrage game, and conditions under which the project owner would delay investment until time j, playing the arbitrage game for j-i years.

Further algebraic simplification presents inequality (5), the final decision model for whether or not to delay investment in the efficiency upgrade. If the inequality holds, the decision-maker chooses to play the arbitrage game. If the inequality does not hold, the decision-maker chooses to invest in the efficiency upgrade. In this inequality, values for RPM auction prices, nominal energy savings, and Capital expenditures can be used to determine the optimal time of investment. If the optimal value of j is equal to i, that would imply that playing the game is not an economically rational activity, and thus the investor should proceed with the investment in the efficiency upgrade.

$$(5)\quad 365B\sum_{i+3}^{j+3}\left(P_{BRA_i}-P_{IA_i}\right)\delta^{j-1}$$
$$+\delta^{j-i}\left[\sum_{i+2}^{i+2}(-C)\delta^{i-1}+\delta^3\sum_{i}^{i+3}365B\left(P_{BRA_i}\right)\delta^{i-1}+\delta^3\sum_{i}^{n}(S)\,\delta^{i-1}\right]$$
$$\geq\sum_{i+2}^{i+2}(-C)\delta^{i-1}+\delta^3\sum_{i}^{i+3}365B\left(P_{BRA_i}\right)\delta^{i-1}+\delta^3\sum_{i}^{n}(S)\,\delta^{i-1}$$

I am interested in solving for combinations of capital cost, energy savings, and RPM prices that would make the inequality hold. For simplicity, the one period arbitrage model (2) is used. By isolating one of the variables, the equation can be solved for conditional values of capital investment (C), energy savings (S), or RPM prices, such that the decision-maker will engage in arbitrage for one period when the inequality condition holds. Data on EE project costs is difficult to obtain, but I plan to utilize energy usage data for three commercial buildings to derive conditional EE project costs such that the building owner would or would not have an incentive to engage arbitrage.

The following decision tree represents the continuous arbitrage game. In period i, the player chooses between investing in the efficiency upgrade (I) and delaying the investment to engage in arbitrage for that period (D). If the player invests, they receive a payout with a net present value (taking time i as the present) of E_i, where E_i is the net present value of the future capital expenditures, capacity payments, and energy savings associated with the efficiency upgrade in period i.

$$E_i = \sum_{i+2}^{i+2}(-C)\delta^{i-1} + 365B\sum_{i+3}^{i+6}\left(P_{BRA_i}\right)\delta^{i-1} + \sum_{i+3}^{n+3}(S)\,\delta^{i-1}$$

If the player chooses to delay, they use the arbitrage strategy for one period by buying out of their capacity commitment at time i+1 and receive a payout of A_i, where A_i is the net present value of the arbitrage payment in that period i.

$$A_i = 365B\sum_{i+3}^{i+3}\left(P_{BRA_i} - P_{IA_i}\right)\delta^{i-1}$$

In period i+1, the game is repeated and the player again faces the decision to invest in the efficiency upgrade (I) or delay (D) and engage in arbitrage again. If the player chooses to invest, they receive the arbitrage payment from delaying in period i and the payment from the upgrade in period i+1. If the player chooses to delay in period i+1, the game is repeated again in period i+2. The game is repeated indefinitely until a final investment is made.

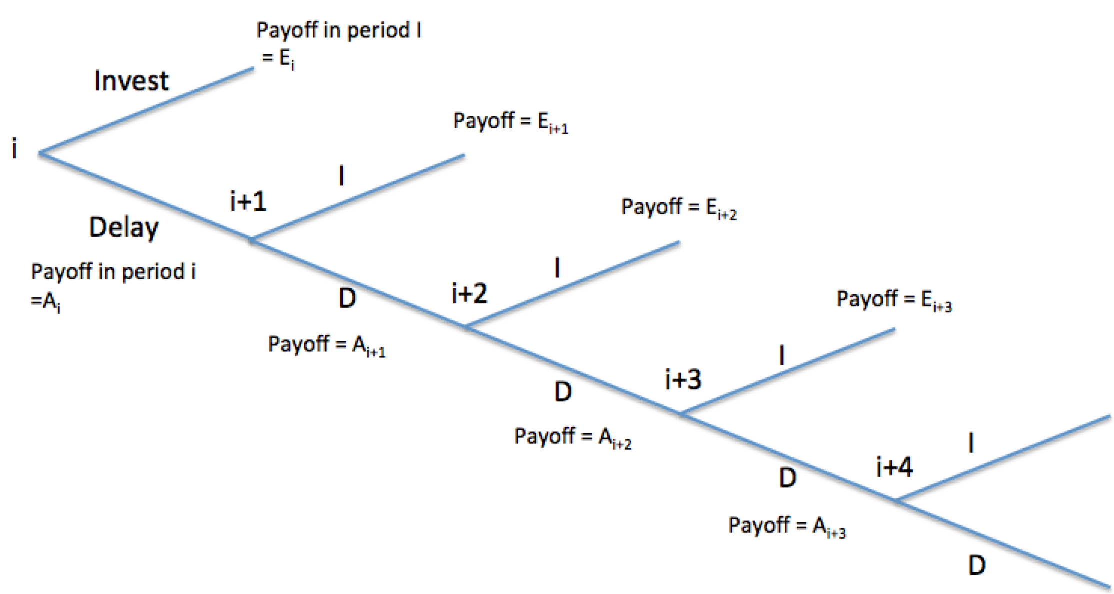

Figure 5: Arbitrage Game Decision Tree

Section 3.2: Arbitrage Game with Uncertainty

The choice between investing in the efficiency upgrade or delaying the investment and engaging in arbitrage is similar to exercising an option. Owners of capacity resources that bid capacity into the BRA essentially have a European style option to delay their investment, which may be exercised by purchasing replacement capacity in the first or third IA. This option is available to all resource owners that are cleared in the BRA, and PJM does not charge anything for it. There is, however, a cost to exercise the option, which PJM prices at the market clearing equilibrium price for the IA auction. Viewing the decision to delay as an option that may or may not be exercised based on the auction prices, as opposed to a defined strategy based on perfect information, allows for the incorporation of uncertainty in the valuation of the game.

The following model presents the decision to invest in the efficiency upgrade or exercise the option to delay as a recursive game with uncertainty in the IA price. The game proceeds as follows: in the first period (time i) the player bids an efficiency upgrade into the BRA for delivery at time i+3. At time i+1, the player observes the IA price and makes a decision to invest and complete the efficiency upgrade for delivery at time i+3, or delay investment and buy out of their commitment in the IA. If the player invests, the game ends and they incur capital expenditures at time i+2 and receive BRA payments and energy savings consistent with the efficiency upgrade, beginning at time i+3. If they delay, they again bid the efficiency upgrade into the BRA for delivery at time i+4 and the game repeats itself. They again face the decision to invest or exercise their option to delay in period i+3. This game is repeated indefinitely until the party makes the decision to stop exercising their option to delay and makes the investment to complete the efficiency upgrade.

This model makes a number of assumptions. First, the BRA price is observed in the first period and remains constant throughout the game. It is also assumed that the incremental auction prices are uniformly distributed such that $P_{IA} \sim U(0, 300)$. The lower bound of this assumption comes from the fact that IA prices are bounded below by zero. Historic values for the IA clearing price have a maximum of 178.85, so I arbitrarily set the upper bound of the distribution to 300 to allow for the possibility of higher clearing prices in future auctions than have historically been observed.

A number of new variables appear in this model. They are as follows:

- V – Overall value of the game ($)
- T – Threshold value for exercising the option ($). If $P_{IA} < T$, the option is exercised and the player chooses to delay the project by an additional period.
- $P(P_{IA} < T\ )$ –The probability of choosing to invest
- $(E\left(P_{IA_i} \middle| P_{IA_i} < T\right) -$ Expected value of the IA price conditional on $P_{IA_i} < T$ ($)

- π – The present discounted value of investing in the efficiency upgrade. This is the discounted summation of the capital expenditures incurred in period i+2 and the annual energy savings over the life of the project. The value of this investment is .$\pi = (-C)\delta^{i+1} + \sum_{i+3}^{n+3}(S)\,\delta^{i-1}$

The following equation represents the value of this recursive game, which repeats itself every time the player exercises the option to delay. I will refer to this as the recursive model.

(6) $V_i = P_{BRA} + P(P_{IA} < T\,)(\pi) + (1 - P(P_{IA} < T\,))[-\left(E\left(P_{IA_i}\middle|P_{IA_i} < T\right) + \delta V_{i+1}\right]$

In this model, the player receives the capacity payment, P_{BRA}, for their initial bid into the RPM. They will make the decision to invest with probability $P(P_{IA} < T\,)$, so the payoff from investment, π is weighted by $P(P_{IA} < T\,)$. The player will choose to exercise the option to delay with probability $(1 - P(P_{IA} < T\,))$, so the payoff from delaying is weighted by $(1 - P(P_{IA} < T\,))$. The payoff from delaying is represented by $[-\left(E\left(P_{IA_i}\middle|P_{IA_i} < T\right) + \delta V\right]$. The first term, $-(E\left(P_{IA_i}\middle|P_{IA_i} < T\right)$, is the expectation for the IA price that the party must pay to exercise the option, conditional on the IA price being below the threshold value. The second term, δV, represents the value of the entire game as it is repeated in the second period. It is equal to the value of the game in the first period, discounted by one period. This accounts for the recursive nature of the game in which, if the option to delay is exercised, the game repeats itself and the player receives the same value from the subsequent game, discounted by one period.

In solving equation (6), the values for $(P(P_{IA} < T\ ))$ and – $(E\left(P_{IA_i} \middle| P_{IA_i} < T\right)$ are derived from the uniform distribution of P_{IA_i}. The values for these terms are $P(P_{IA} < T\ ) = \frac{300-T}{300}$ and $E\left(P_{IA_i} \middle| P_{IA_i} < T\right) = \frac{1}{2}(T)$. Also, δ is set equal to 0.952. Solving equation (6) for V_i and inserting the values for $(P(P_{IA} < T\ ))$ and – $(E\left(P_{IA_i} \middle| P_{IA_i} < T\right)$ yields equation (7).

$$(7) \qquad V_i = \frac{\left[P_{BRA} + \frac{300-T}{300} * \pi - \left(1 - \frac{300-T}{300}\right) * \left(\frac{T}{2}\right)\right]}{1 - .952\left(1 - \frac{300-T}{300}\right)}$$

The results of equation (7) indicate that the decision to invest or delay in this model is independent of P_{IA_i}, and that, for different combinations of P_{BRA}, C, and S, one either invests in the first period or delays infinitely. This condition is a result of V_i being a monotonically increasing or monotonically decreasing function in T (depending on the values of P_{BRA}, C, and S). Equations (8) and (9) present the first and second order derivatives for V.

$$(8) \qquad \frac{dV_i}{dT} = \frac{315.126P + 0.525T^2 - 331.015T - 15.889\pi}{(315.126 - T)^2}$$

$$(9) \qquad \frac{d^2V_i}{dT^2} = \frac{104311 - 630.252P + 0.000347T + 31.777\pi}{(T - 315.126)^3}$$

The first and second order derivatives of V_i illustrate the monotonicity of this function over the range of T. When the first derivative is positive, the second derivative will also be positive, indicating that the function is monotonically increasing. As a result, the strategy that yields the highest value for the game is to delay indefinitely. When the first derivative is negative, the second derivative will also be negative, indicating that the optimal strategy in this circumstance is to invest in the first period. Thus, there is a "knife edge" property to this game, wherin there is point at which, based on the values of P_{BRA}, C, and S, the function switches from being monotonically increasing to monotonically decreasing, and the optimal strategy switches from delaying indefinitely to investing in the first period.

The following conditions always hold and enable the illustration of the monotonicity of V_i:

- $0 < T < 300$
- $P \geq 0$
- $\pi \geq 0$

As a result, the demoninator of the first order derivative, $(315.126 - T)^2$, is positive for all values of T. Therefore, the first order derivative (8) is greater than zero if and only if the numerator is also greater than zero. The condition under which the numerator, $315.126P + 0.525T^2 - 331.015T - 15.889\pi$, is greater than zero, is expressed in equation (10).

(10) $P > -0.00166T^2 + 1.05T + 0.05042\pi$

Similarly, the denominator of the second order derivative, $(T - 315.126)^3$, is always negative. As a result, the second order derivative (9) is positive if and only if the numerator, $104311 - 630.252P + 0.000347T + 31.777\pi$, is also negative. This condition is expressed in equation (11)

(11) $P > 165.50 + 0.05042\pi + 5.506 * 10^{-7}(T)$

For all numerical combinations of P and π (a function of C and S) over the range of T that are relevant to this model, condition (10) implies condition (11), leading to the conclusion that when the first derivative is positive, the function is monotonically increasing and the optimal threshold value for T is the upper bound of the distribution. Thus, in this case, the party will delay the project indefinitely.

Similarly, if the first order derivative is negative, the second derivative will be as well. The conditions for a negative first and second derivative are expressed in equations (12) and (13), respectively.

(12) $P < -0.00166T^2 + 1.05T + 0.05042\pi$

(13) $P < 165.50 + 0.05042\pi + 5.506 * 10^{-7}(T)$

For all numerical combinations of P and π over the range of T that are relevant to this model, condition (12) implies condition (13). This implication can be seen by examing the extreme cases of T, where $T = 0$ and $T = 300$. When $T = 300$, the conditions in (12) and (13) are both $P < 165.50 + 0.05042\pi$. Since the conditions are exactly the same in this case, (12) must imply (13). When $T = 0$, condition (12) is $P < 0.05042\pi$. Condition (13) is $P < 165.50 + 0.05042\pi$. If $P < 0.05042\pi$, as is the condition in (12), then $P - 0.05042\pi < 0$. As a result, $P - 0.05042\pi < 165.50$, implying that $P < 165.50 + 0.05042\pi$ must hold.

This implies that when the first derivative is negative, the function is monotonically decreasing, giving an optimal threshold value for T of zero, implying that when this is the case there is no incentive to delay and the investment in the efficiency upgrade will always be made in the first period.

Chapter 4: Empirical Analysis

Section 4.1: Analysis

The decision framework in Chapter 3 is used in an empirical analysis of the conditions necessary for one to play the arbitrage game or follow through with investment in an EE upgrade. A comparison of empirical results from the two models illustrates the difference between investment decisions under perfect information and uncertainty. Data obtained from PJM was used to calculate the revenue generated from RPM bids. Building energy data from the Philadelphia Navy Yard was used to generate representative building demand profiles and provide information on electricity costs.

The following analysis uses data from three buildings in the Navy Yard as Navy Yard buildings 7, 10, and 41 were chosen, based on levels of peak demand, as representative large, medium, and small consumers of electricity. Building 7, which has a peak demand of 2.24 MW, is a textile fabrication plant with a small section of offices attached to it. Building 10, which has a peak demand of 256.2 kW, is a medium-sized office building. Building 41, which has a peak demand of 15.9 kW, is a small office building.

For each building, three cases are modeled to represent different levels of BRA prices. A 'high BRA price' case is used to represent the maximum BRA price observed in the RPM data. A 'low BRA price' case is used to represent the minimum observed BRA price. An 'average BRA price' case is used to represent the average of all observed BRA prices. The following chart displays the BRA prices for the high, average, and low BRA price cases.

High BRA Price	\$245.00
Average BRA Price	\$163.67
Low BRA Price	\$110.04

Table 4: BRA Prices

The empirical data for BRA prices and building size is inserted into the model. Time *i* is set equal to one and j is set equal to two. The inequality is then solved for the IA price as a function of capital cost (C) and energy savings (S) for each case. The investment conditions, separated by building and case, are outlined below.

The parameters for Building 7 are:

- Peak demand = 2.24 MW
- B = 0.672 MW

The following parameters define the high BRA price case:

- $P_{BRA} = \$245/MW - day$
- r = 0.05
- $\delta = \frac{1}{1+.05} = 0.952$
- $i = 1$
- j = 2

- n = 50

By inserting the parameters for the Building 7 high BRA price case into equation (5) and simplifying, we arrive at the inequality constraint for the IA price (14), conditional on the values of C and S, under which one would choose to play the arbitrage game and delay investment in the efficiency upgrade.

(14) $P_{IA} \leq 203.301 + .000196(C) - .00413(S)$

The following parameters define the average BRA price case:

- $P_{BRA} = \$163.67/MW - day$
- r = 0.05
- $\delta = \frac{1}{1+.05} = 0.952$
- $i = 1$
- j = 2
- n = 50

By inserting the parameters for the Building 7 average BRA price case into equation (5) and simplifying, we arrive at the inequality constraint for the IA price in equation (15). Similar to equation (14), equation (15) outlines the conditional IA price constraint, for the Building 7 average BRA price case, for which one would choose to engage in arbitrage and delay investment in the efficiency upgrade.

(15) $P_{IA} \leq 135.813 + .000196(C) - .00413(S)$

The following parameters define the low BRA price case:

- $P_{BRA} = \$110.04/MW - day$
- r = 0.05
- $\delta = \frac{1}{1+.05} = 0.952$
- $i = 1$
- j = 2
- n = 50

By inserting the parameters for the Building 7 low BRA price case into equation (5) and simplifying, we arrive at the inequality constraint for the IA price in equation (16). Similar to equation (14), equation (16) outlines the conditional IA price constraint, for the Building 7 average BRA price case, for which one would choose to engage in arbitrage and delay investment in the efficiency upgrade.

(16) $P_{IA} \leq 91.311 + .000196(C) - .00413(S)$

The parameters for Building 10 are:

- Peak Demand = 0.2562 MW
- B = 0.07686 MW

By inserting the parameters for Building 10 and the parameters for the high, average, and low BRA price cases, we arrive at the constraint for the IA price conditional on C and S. Equations (17), (18), and (19) outline the constraints for the Building 10 high, average, and low BRA price cases, respectively.

(17) $P_{IA} \leq 203.301 + 0.00168(C) - 0.0354(S)$

(18) $P_{IA} \leq 135.813 + 0.00168(C) - 0.0354(S)$

(19) $P_{IA} \leq 91.311 + 0.00168(C) - 0.0354(S)$

The conditions for Building 41 are:

- Peak Demand = 0.0159 MW
- B = 0.00477 MW

By inserting the parameters for Building 41 and the parameters for the high, average, and low BRA price cases, we arrive at the constraint for the IA price conditional on C and S. Equations (20), (21), and (22) outline the constraints for the Building 10 high, average, and low BRA price cases, respectively.

(20) $P_{IA} \leq 203.301 + 0.0277(C) - 0.5583(S)$

(21) $P_{IA} \leq 135.813 + 0.0277(C) - 0.5583(S)$

(22) $P_{IA} \leq 91.311 + 0.0277(C) - 0.5583(S$Section 4.2: Results

Perfect Information Model

The following figures display the conditions under which the arbitrage strategy is economically rational for each building type and price scenario. For different values of energy savings and capital investment, the following contour maps display a threshold value for the IA price. These threshold values are conditional on the value of the BRA price. If the IA price is below the threshold value then the difference between the BRA price and the IA price is large enough to make the arbitrage strategy profitable. Similarly, if the IA price is greater than the threshold value, then the difference between the BRA and IA prices is too small to justify the arbitrage game, and the investment is undertaken to follow through with the planned energy efficiency upgrade. Put simply, the contour plots display the threshold at which on would choose to play the arbitrage game or not.

The IA price can never be negative. As a result, if the IA threshold value is less than or equal to zero, the arbitrage strategy will never be used. Thus, any combination of values for energy savings and capital investment cost that lies to the upper left of the line marked “0” on the contour maps indicates that parties should always follow through with the EE upgrade. In expected value terms, the expectation for the IA price, historically, has been $58.77/MW-day. Thus, whenever the IA threshold is greater than $58.77/MW-day, the expectation is that the IA price will be lower than the threshold value, and thus there is an incentive to engage in arbitrage activity. Any combination of values for energy savings and capital investment cost that lies to the lower right of the contour line marked demarking the expected IA price indicates that in expectation, the arbitrage strategy will be profitable.

The results for buildings 7 and 10 are almost identical For these buildings, the cutoff values for the cases with high BRA prices are shifted very slightly to the left with respect to the “low” case. The results for building 41, however, vary greatly from those of buildings 7 and 10.

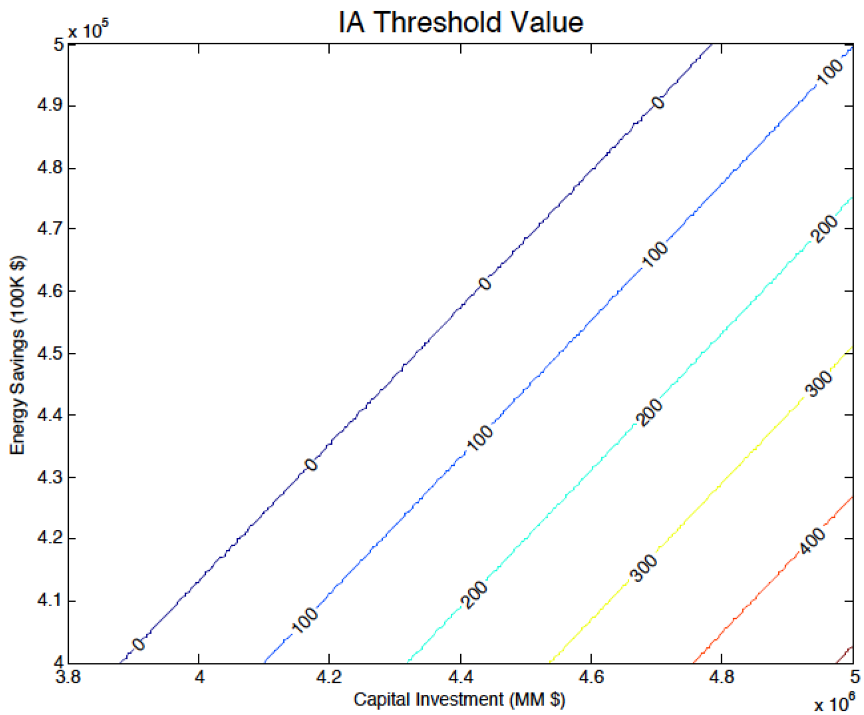

Figure 6: Building 7 – High BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

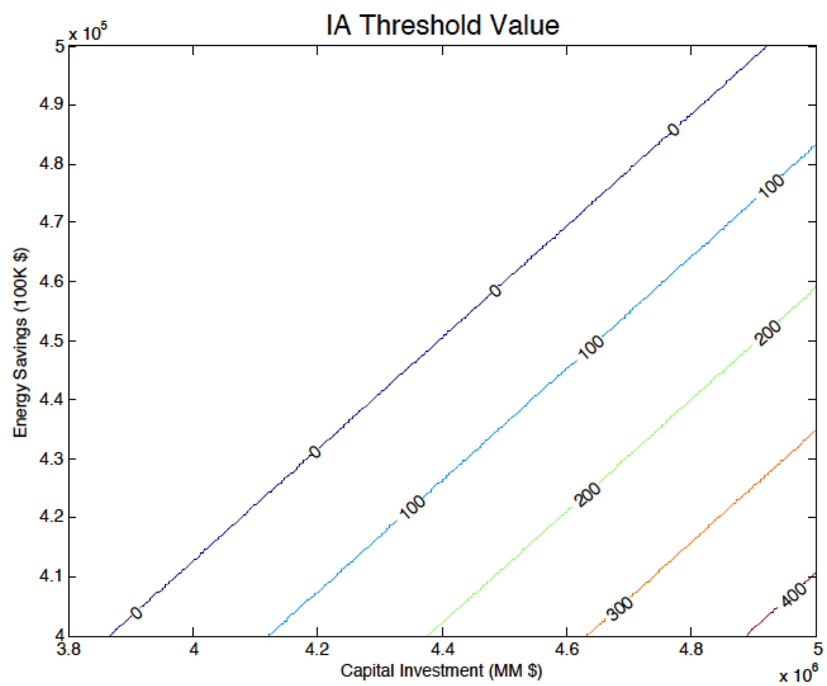

Figure 7: Building 7 – Average BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

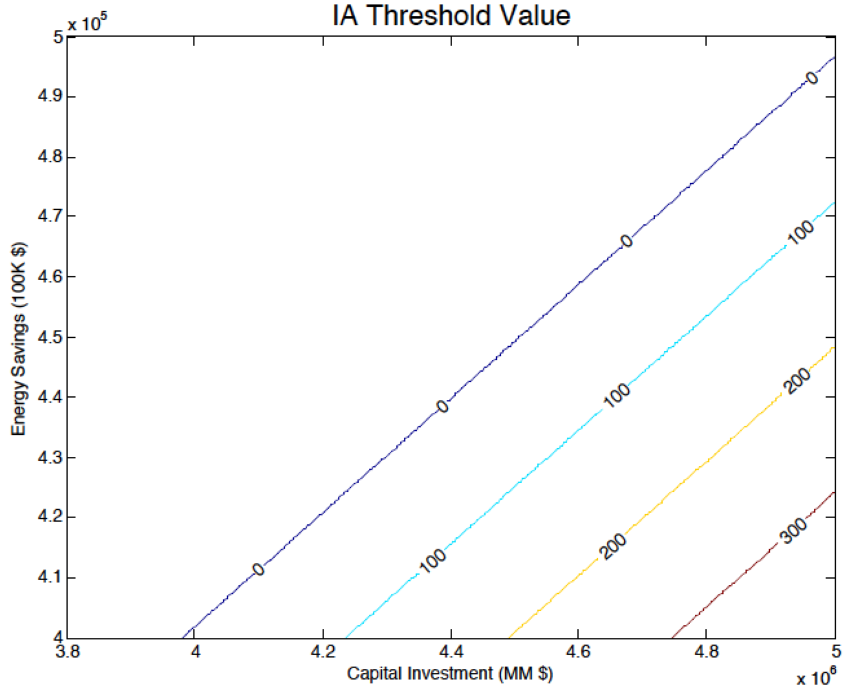

Figure 8: Building 7 – Low BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

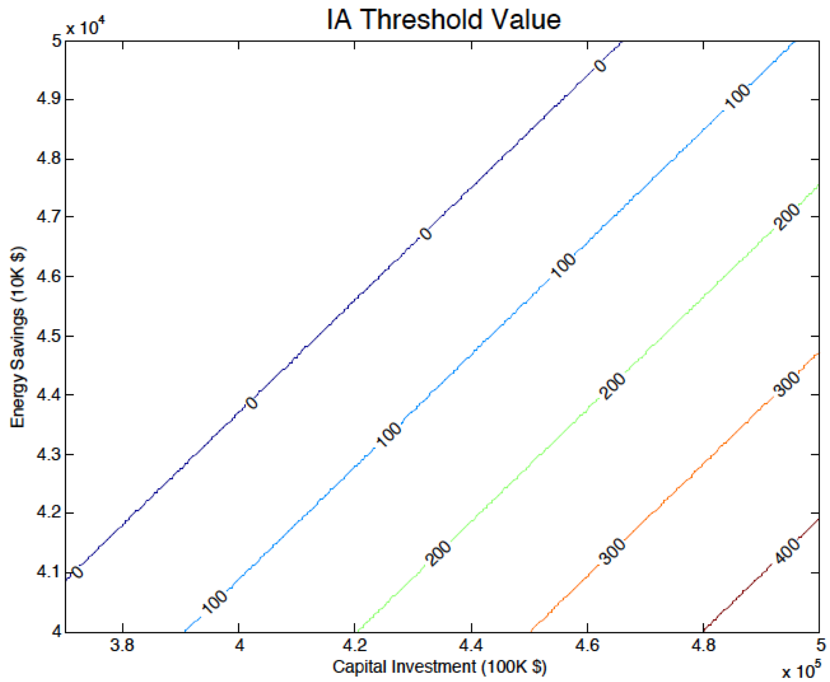

Figure 9: Building 10 – High BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

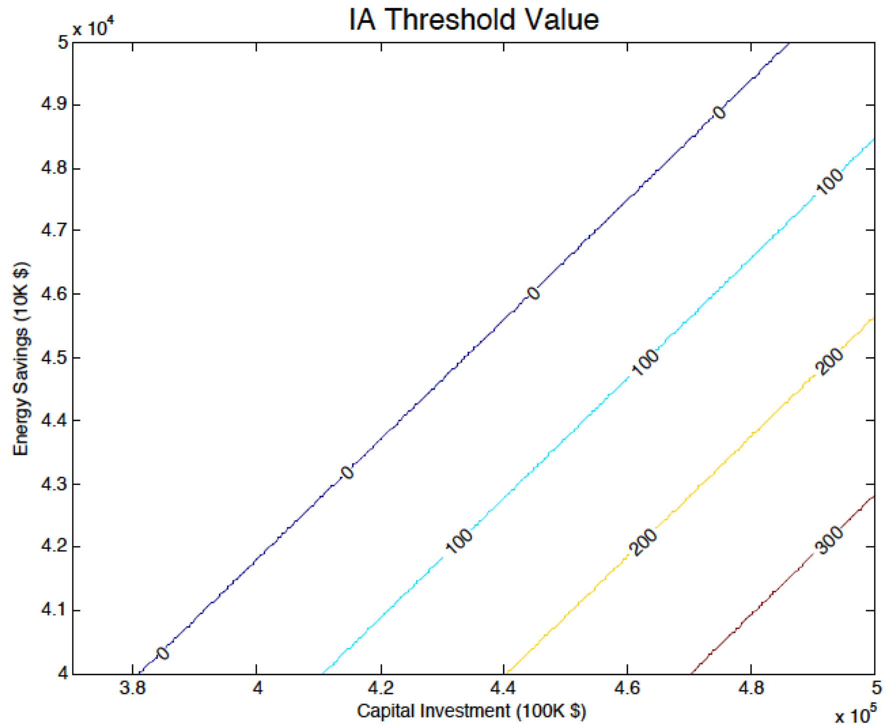

Figure 10: Building 10 – Average BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

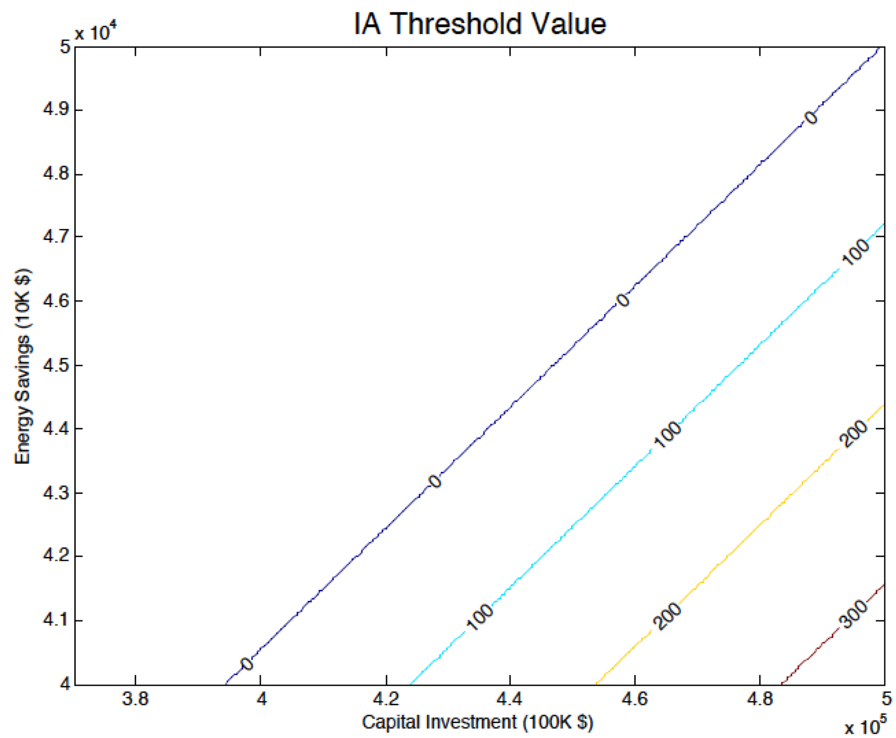

Figure 11: Building 10 – Low BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

For the “High” BRA price case for Buildings 7 and 10, the contour line marked “0” lies along the annual capital investment to annual energy savings ratio of 9.6:1. Similarly, the line demarking the expected value of the IA price lies along the annual capital investment to annual energy savings ratio of 9.9:1. Thus, the arbitrage game is never played in cases where the value of the total capital investment cost is less than 9.6 times greater than that of the energy savings and is expected to be profitable when the total capital investment is greater than 9.9 times the value of the annual energy savings.

The “Average” BRA price case has slightly higher cutoff ratios than the “High” BRA price case. When the total capital investment to annual energy savings ratio is less than 9.9:1, the arbitrage game is never played. Similarly, when the total capital investment is greater than 10.1 times the value of the annual energy savings, the arbitrage game is expected to be profitable. The “Low” BRA price case has even higher values for the cutoff ratios. At total capital investment to annual energy savings ratios below 10.1:1, the arbitrage game is never played. When the total capital investment to annual energy savings ratio is greater than 10.4:1, the arbitrage game is profitable in expectation.

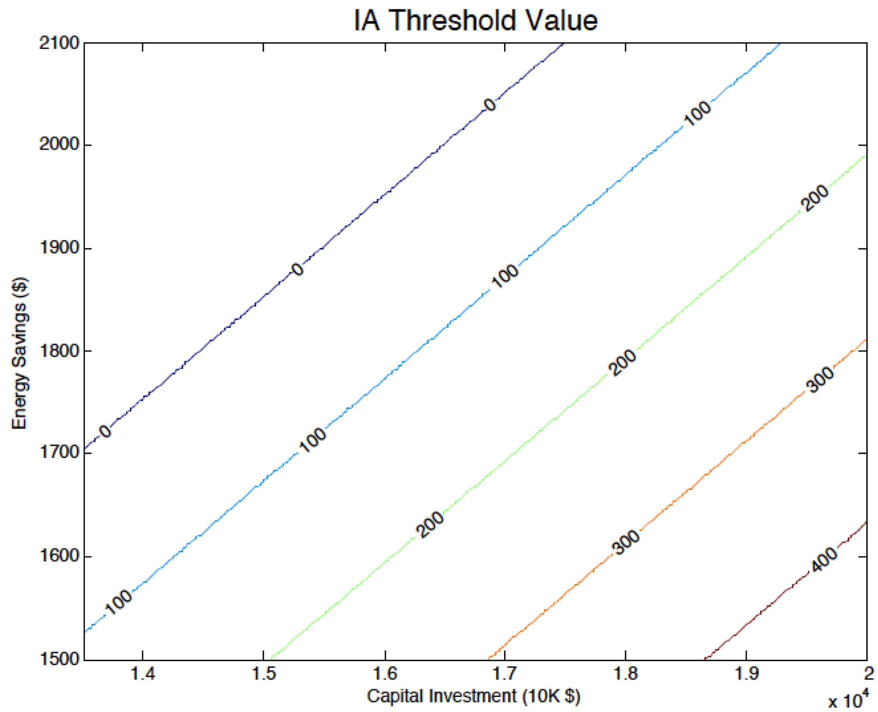

Figure 12: Building 41 – High BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

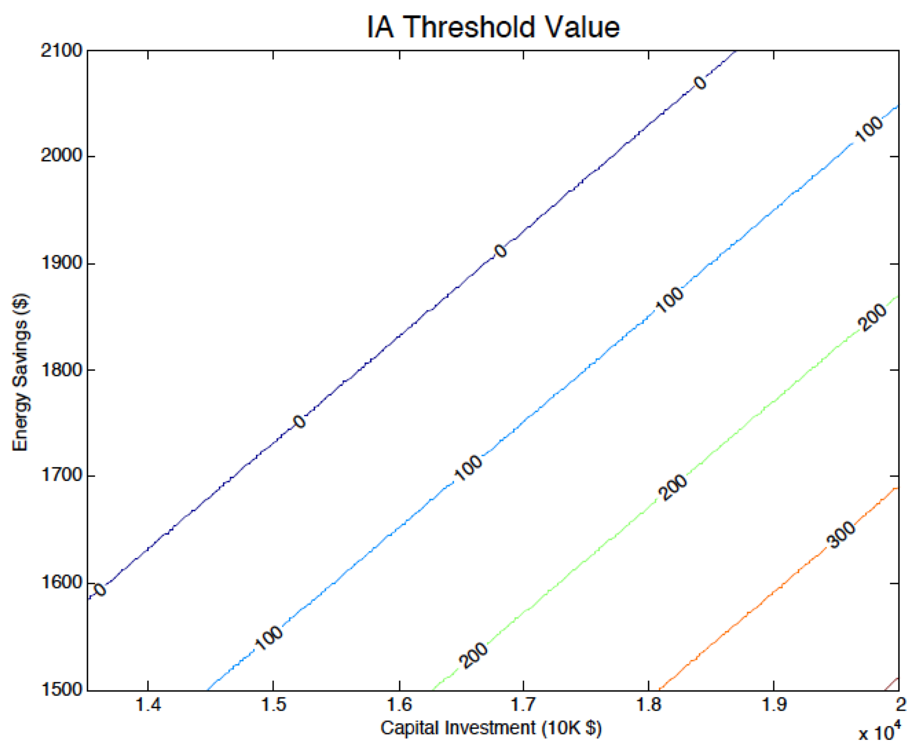

Figure 13: Building 41 – Average BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

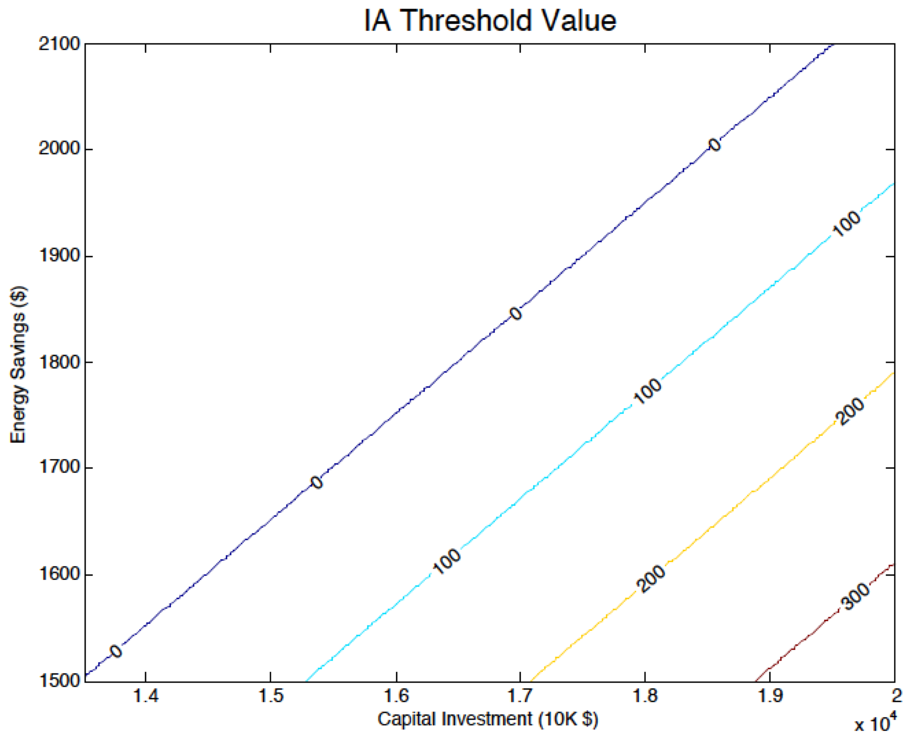

Figure 14: Building 41 – Low BRA Price Case. The blank space in the upper left corner is due to the fact that IA prices may never be negative. As a result, there are no contour lines below the IA threshold line with a value of zero.

For the "High" BRA price case for Building 41, the contour line marked "0" lies along the annual capital investment to annual energy savings ratio of 8.5:1. Similarly, the line demarking the expected value of the IA price lies along the annual capital investment to annual energy savings ratio of 9.0:1. Thus, the arbitrage game is never played in cases where the value of the total capital investment cost is less than 8.5 times greater than that of the energy savings and is expected to be profitable when the total capital investment is greater than 9.0 times the value of the annual energy savings.

The “Average” BRA price case has slightly higher cutoff ratios than the “High” BRA price case. When the total capital investment to annual energy savings ratio is less than 9.1:1, the arbitrage game is never played. Similarly, when the total capital investment is greater than 9.5 times the value of the annual energy savings, the arbitrage game is expected to be profitable. Much like buildings 7 and 10, the “Low” BRA price case has higher cutoff values than the high and average cases. At total capital investment to annual energy savings ratios below 9.4:1, the arbitrage game is never played. When the total capital investment to annual energy savings ratio is greater than 9.8, the arbitrage game is profitable in expectation.

Recursive Model

The following figures display the conditions under which the arbitrage strategy is economically rational for each building type and price scenario in the recursive game. The following figures display threshold values for investment in the efficiency upgrade. The threshold line shows the ratio of capital investment costs to annual energy savings that makes the player indifferent between investing in the first period or delaying indefinitely. For each of the BRA price cases, if the combination of (C) and (S) lies to the upper left of the threshold line, the player chooses to invest in the first period. If the point lies to the lower right of the threshold line, the player delays indefinitely. Essentially, the line shows the ratio of capital investment costs to annual energy savings that makes the player indifferent between investing in the first period or delaying indefinitely.

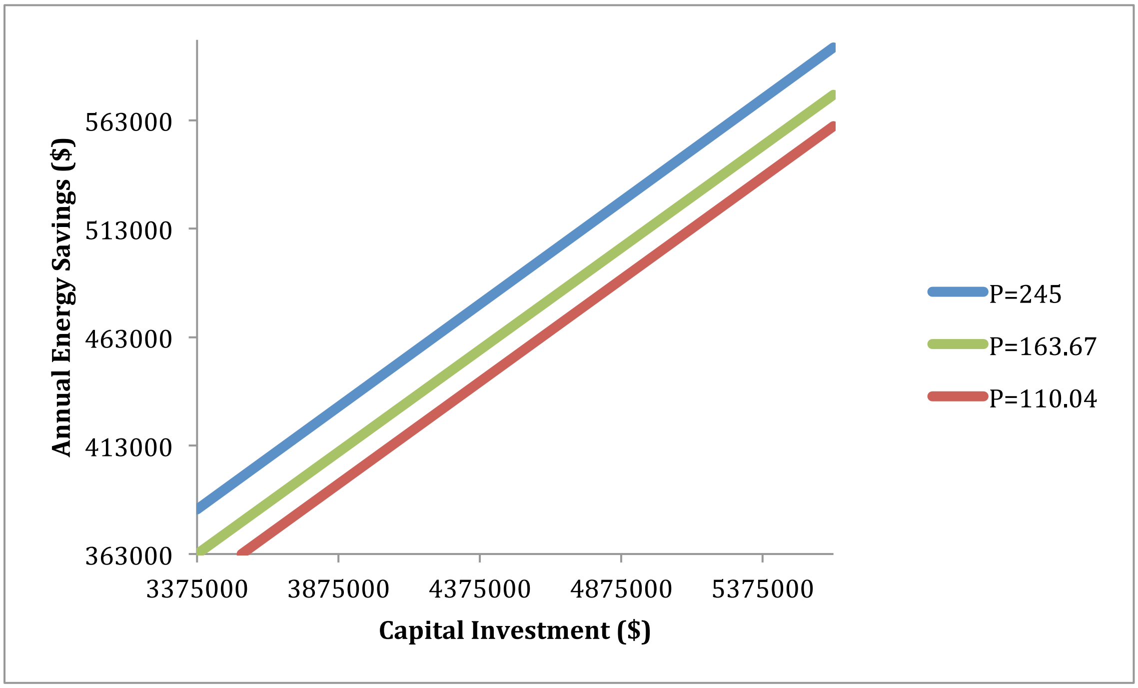

Figure 15: Building 7 Threshold for Investment

The threshold line for Building 7 indicates that, for the high BRA price case, the player is indifferent between investing and delaying if the ratio of capital investment cost to annual energy savings is equal to 8.8:1. If this ratio is larger than 8.8:1, the player will choose to delay indefinitely, and if it is lower than 8.8:1, the player will invest in the first period. For the average BRA price case, the player will invest when this ratio is lower than 9.3:1 and choose to delay indefinitely if it is higher than 9.3:1. For the low BRA price case, the player is indifferent between investing and delaying when this ratio is equal to 9.7:1.

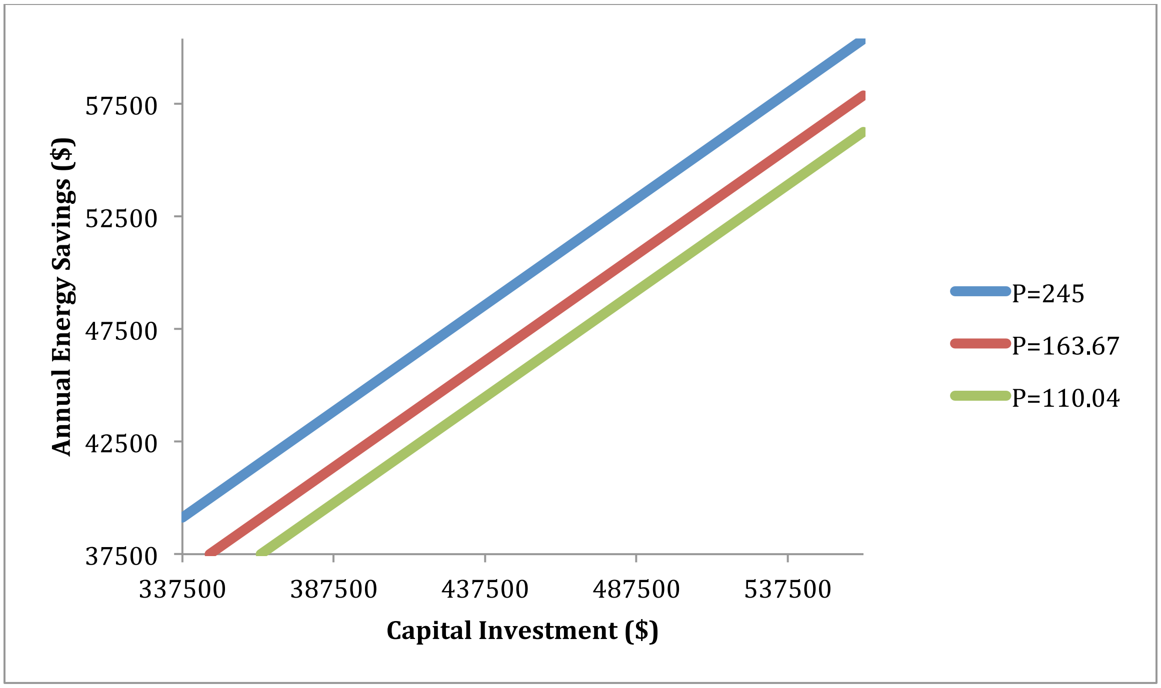

Figure 16: Building 10 Threshold for Investment

The threshold lines for Building 7 lie along slightly lower capital investment to annual energy savings ratios than those for Building 10. The results for Building 10 indicates that, for the high BRA price case, the player is indifferent between investing and delaying if the ratio of capital investment cost to annual energy savings is equal to 8.6:1. If this ratio is larger than 8.6:1, the player will choose to delay indefinitely, and if it is lower than 8.6:1, the player will invest in the first period. For the average BRA price case, the player will invest when this ratio is lower than 9.2:1 and choose to delay indefinitely if it is higher than 9.2:1. For the low BRA price case, the player is indifferent between investing and delaying when this ratio is equal to 9.7:1.

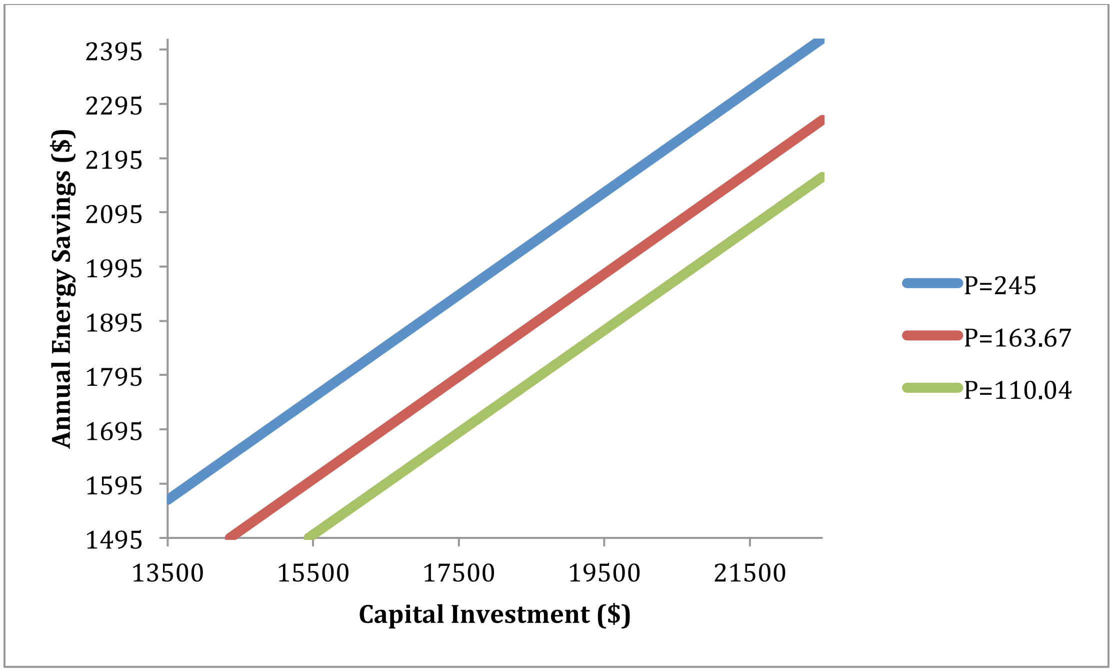

Figure 17: Building 41 Threshold for Investment

Building 41 has a slightly larger range of threshold ratios across BRA prices than both Buildings 7 and 10. The results for Building 41 indicates that, for the high BRA price case, the player is indifferent between investing and delaying if the ratio of capital investment cost to annual energy savings is equal to 8.6:1. If this ratio is larger than 8.6:1, the player will choose to delay indefinitely, and if it is lower than 8.8:1, the player will invest in the first period. For the average BRA price case, the player will invest when this ratio is lower than 9.6:1 and choose to delay indefinitely if it is higher than 9.6:1. For the low BRA price case, the player is indifferent between investing and delaying when this ratio is equal to 10.4:1.

Both the recursive model and the perfect information model yield similar results. The range of threshold ratios for the recursive game is slightly larger for each building type than that of the perfect information game. The threshold ratios, above which one would delay investment by engaging in arbitrage, range from 9.0:1 to 10.4: for the perfect information game. The ratios above which one would choose to delay in the recursive game range from 8.6:1 to 10.4:1. This indicates that the recursive case is slightly more sensitive to building size and BRA prices than the perfect information game, however the overall cutoff ratios are very close for both models.

Chapter 5: Conclusion

The results of the empirical analysis for the perfect and imperfect information models reveal a number of conclusions about the ability of energy efficiency resources to engage in arbitrage behaviors within PJM's capacity market. These results indicate that there are significant opportunities and incentives for energy efficiency resources to engage in arbitrage. While these incentives exist for buildings of all sizes, the models indicate that there is a larger incentive for buildings with smaller electricity demand to engage in this type of behavior. Furthermore, incentives to engage in arbitrage within the capacity market are largely dependent on the magnitude of capital investment costs, annual energy savings, and the clearing price for capacity in the Base Residual Auction.

The results of the perfect information model indicate that there is an incentive, in expectation, for energy efficiency resource owners to engage in arbitrage when the ratio of the capital investment cost to annual energy savings is greater than a threshold ratio. This threshold ratio ranges from 9.0:1 to 10.4:1 for the three representative buildings and price cases that were modeled. Similarly, this threshold ranges from 8.6:1 to 10.4:1 for the cases modeled in the imperfect information model. Most developers target a total capital investment to annual energy savings ratio of no more than 4:1 for efficiency upgrades. However, capital costs for efficiency upgrades vary based on the scope of the project and the design of the building. As a result, many efficiency upgrades have a total capital investment to annual energy savings ratio that ranges from 5:1 to 10:1. In comparison with cheaper efficiency upgrades, the arbitrage strategy would not be profitable. Though in comparison with more extensive efficiency projects, there is a significant opportunity to profitably engage in capacity market arbitrage.

For each BRA price, the results of the models indicate that the capital investment to annual energy savings threshold ratios are lower for buildings with smaller loads. This suggests that there is a larger incentive to engage in arbitrage for owners of small buildings. This is possibly due to the fact that energy costs do not scale in direct proportion to building size. Buildings with larger loads in the Philadelphia Navy Yard pay slightly lower electric rates. This may account for differences in capital cost to energy savings threshold ratios for different sized buildings.

The empirical analysis for both models show that the decision to invest in an efficiency upgrade or delay and engage in arbitrage is largely dependent on capital investment costs, annual energy savings, and the BRA clearing price. For all three buildings in the two models, the capital investment to annual energy savings ratios necessary to incentivize arbitrage behavior are larger for the cases with lower BRA prices. This implies that the reduction in arbitrage payments as a result of the lower BRA price reduces the incentive to engage in arbitrage. For the perfect information model, the upper bound of the IA price necessary to incentivize arbitrage behavior becomes more relaxed as the capital investment to energy savings ratio increases. In some cases, for very large capital investment to savings ratios, there is an incentive to engage in arbitrage even when the IA price is higher than the BRA price and arbitrage payments would be negative. This implies that the heavier discounting of capital costs and energy savings resulting from a delay in investment is the predominant factor in the decision to delay and engage in arbitrage. The decision to delay investment in the imperfect information model is independent of the IA price, leading to a similar conclusion that the predominant factor in choosing to engage in arbitrage is the ability to delay payments from investment in the efficiency upgrade.

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