Dynamic Pricing: Potential Wholesale Market Benefits in New York State

October 21, 2009

Draft for Discussion Purposes Only

ACKNOWLEDGEMENTS

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I. EXECUTIVE SUMMARY

Efforts to address the economic, environmental and energy challenges facing New York State have focused attention on the role of the electric system in providing solutions. As the State's needs evolve, policymakers, regulators and industry leaders are examining ways the electric system can also evolve to serve the state's needs.

One such solution could be the further adoption of dynamic pricing of electricity, whereby the price of retail electricity would vary with the underlying wholesale market costs. In contrast to flat rates paid by consumers for each kilowatt-hour (kWh) of electricity consumed, dynamic pricing provides a rate structure with variable (or dynamic) rates that reflect supply and demand conditions in the wholesale market. Dynamic rates would encourage consumers to adjust energy usage to take advantage of lower priced energy in low demand hours and to limit consumption in higher demand high priced hours. As a result, consumers should benefit from a more efficient electric system.

Demand for electricity is uneven. Consumption in the top one percent of the hours of the year accounts for more than 10 percent of system peak demand. Actions taken to reduce electric demand during this relatively small number of peak hours can significantly reduce total annual electricity costs. Dynamic pricing targets these peak loads, reducing the need for expensive additional reserve generation and transmission capacity.

At the wholesale level, the electric power industry abandoned average cost pricing more than a decade ago. However, at the retail level only the largest industrial and commercial customers have been fully afforded the opportunity to take advantage of dynamic rates. The development of lower cost Advanced Metering Infrastructure (AMI) and digital communications is making the transition to dynamic pricing for a broader range of customers more feasible.

Generally, AMI deployment is viewed as the first step in the rollout of the smart grid, an investment that is receiving increased attention at both the state and federal level. For example, the state of California has approved universal deployment of AMI. California's investor-owned utilities have been ordered to institute dynamic pricing as the default tariff for all customer classes where legal restrictions do not prevent such a change from being implemented.

Many of the larger commercial and industrial customers in New York State are already on dynamic rates, but the majority of customers does not have AMI and are not on a dynamic pricing rate. Most customers have no signal or substantial incentive to reduce their consumption when generation supply becomes scarce and wholesale prices increase. The inability of customers to respond to price signals makes it more costly for the New York Independent System Operator (NYISO) to maintain a balance between supply and demand.

The NYISO's least-cost, bid-based dispatch employs Locational Based Marginal Prices (LBMP). These prices provide a transparent mechanism for identifying the cost of energy at any point throughout the state. Providing these LBMP signals to retail customers is a key step in enabling consumers to better manage their electricity costs. Dynamic pricing may also facilitate energy efficiency, as well as allow better management of in-home devices and other technologies that can respond to price information.

The NYISO's Independent Market Advisor has recommended retail rate reform as the preferred method for eliciting greater customer response to underlying wholesale electric market costs.[1] Demand elasticity, which is the willingness to adjust consumption based on prices, is an essential component of efficient markets because it allows the markets to clear at a price that is more reflective of its value to consumers.

This white paper identifies the wholesale market benefits that could be expected if all retail customers were provided dynamic price signals, similar to those price signals now available to participants in New York's wholesale electricity markets.

The Base Case analysis was conducted as follows:

- *Comparable Dynamic and Fixed Rates were Defined:* The first step developed fixed rates and dynamic rates consistent with wholesale market conditions for a 2010 forecast year, as projected in a wholesale market simulation model and a separate capacity price projection.[2] The dynamic rates vary hourly based on LBMPs, plus capacity prices allocated to approximately the top one percent of demand hours, plus other charges, such that the average customer's annual energy costs would be unchanged from the fixed rate scenario if demand remained unchanged. The analysis focuses on a representative residential customer class and a representative commercial/industrial class in each of four zones that capture the diversity of the state's power system.
- *The Effects of Dynamic Pricing on Demand were Estimated:* The second step estimated the changes that could take place in hourly demand profiles as customers respond to the dynamic prices, using the Brattle Group's Pricing Impact Simulation Model (PRISM). This model applies price elasticities of demand to the hourly difference between the dynamic rate and the fixed rate. The elasticities, key inputs to the model, are derived from several recent dynamic pricing pilot programs.
- *Wholesale Market Impacts were Simulated:* The third step quantified the effects of changes in demand on wholesale energy prices using a market simulation model.[3] The analysis conservatively assumes that suppliers' bids to supply energy remain the same in spite of the competitive pressure imposed by price-responsive demand.

[1] *2008 State of the Market Report, New York ISO Electricity Markets,* May 2009

[2] Locational-based marginal prices (LBMPs) were simulated for 2010 using the DAYZER model, which was calibrated to actual historical market conditions then updated to reflect 2010 supply and demand conditions. 2010 capacity prices were assumed to remain at current prices from spot auctions, except in New York City where summer installed capacity prices were assumed to increase to $9 per kW-month (unforced capacity) following the retirement of the Poletti generation unit.

[3] This study employed the DAYZER market simulation model developed by Cambridge Energy Solutions. DAYZER uses the same general principles at the NYISO dispatch algorithm to mimic system dispatch and LBMPs in New York.

In addition to a Base Case, three alternative scenarios were simulated in which: (1) in-home display devices that provide customers with real-time feedback on their usage and costs are deployed along with dynamic pricing. In-home displays have been proven to induce conservation in about a dozen pilot programs; (2) capacity prices rise to the Net Cost of New Entry (Net CONE), reflecting future market conditions in which there is no longer a surplus of capacity; (3) elasticities of demand are approximately twice as high as in the Base Case, reflecting the effects of enabling technologies on customers' ability to shift their consumption.

The estimated impact of dynamic pricing was quantified across three sets of metrics as follows:

- *Demand Reduction*: Dynamic pricing could result in system peak demand reductions in the range of 10 to 14 percent, from a projected value of 34,000 megawatts (MW), and with a 13 to 16 percent reduction in New York City and an 11 to 14 percent reduction on Long Island. While it is clear that dynamic pricing could reduce peak demand, its impact on overall electricity consumption is less clear-cut. The modeling indicates that annual energy usage and electric sector CO_2 emissions could increase by approximately 0.5 percent as a result of lower retail prices in the majority of hours. However, energy usage and emissions could decrease if in-home displays were deployed with dynamic pricing, making customers more aware of their energy usage and costs.
- *Cost Reduction:* Total resource costs decrease by a range of $143 million to $509 million per year, or 3 percent to 6 percent. Market-based customer costs decrease by $171 million to $579 million per year, or 2 to 5 percent (excluding AMI deployment costs), depending on capacity price levels and whether in-home display devices are deployed and create a conservation effect.
- *Social Welfare Improvement:* Social welfare is the measure of overall prosperity of society. It is the sum of the "consumer surplus," the value consumers derive in excess of the price paid; and the "producer surplus," suppliers' profits. Changes in consumer surplus account for changes in value, not just cost;[4] changes in producer surplus account for changes in revenues as well as costs. These individual metrics also account for transfers between consumers and producers, for example if prices change. This study found that dynamic pricing could improve consumer surplus by $162 million to $572 million per year and could improve total social surplus by $141 million to $403 million per year.

It should be noted that this study did not consider how the efficiency of customer end-use equipment could change with dynamic pricing. In actual implementation, dynamic pricing could be deployed as part of a larger demand-side strategy that also includes in-home displays and cost-effective energy efficiency measures. Moreover, the substantial economic savings from dynamic pricing could help mitigate the initial investment cost of energy efficiency initiatives. Such a combined strategy could result in substantially lower costs and emissions.

[4] For example, consumer surplus accounts for the loss in wellbeing experienced by customers as they reduce their consumption during critical peak hours in response to higher prices and the gain in wellbeing they experience as they increase consumption during those non-critical hours where prices are lower than the otherwise applicable flat rate.

This study also assumes that generation supply is static. In reality, suppliers would eventually be expected to change their investment decisions and possibly accelerate generation retirements if dynamic pricing flattened the load shape thereby reducing the economic viability of some plants while increasing the viability of others. Thus, the short-run changes in LBMPs observed in this study would be expected to change and likely diminish over time. However, the estimated cost and welfare impacts are relatively more robust over a longer term. Most of the estimated benefits derive from reduced capacity requirements, not from changes in LBMPs, or capacity prices.

Since similar benefits might be expected to accrue in subsequent years, it is likely that the present value of benefits over the next two decades would be several times the benefits estimated for the year 2010. Thus, dynamic pricing could have significant positive impacts in New York if it were to be deployed on a widespread basis.

This study used proxy retail rates rather than actual retail rates and modeled rather than measured retail price response. Actual retail rate design accommodates a variety of goals that may not be reflected in the proxy rates used in this study. It should also be noted that a variety of barriers to the widespread deployment of dynamic pricing exist at this time. A more detailed evaluation of the benefits of dynamic pricing and the potential impacts on individual customers could be pursued through the design efforts of, and possible pilot efforts by, New York's load serving entities and the New York State Public Service Commission (NYPSC).

Given the magnitude of these potential benefits, serious consideration should be given to further evaluation of the widespread deployment of dynamic pricing. The NYSPSC is currently evaluating the benefits and costs of deploying AMI in the state. Given the potential for wholesale market benefits, and the possible future needs to integrate electric vehicles and other devices on the system, the NYSPSC is faced with making important decisions about the future of retail metering and retail rates in New York. The NYISO is interested in working with the NYSPSC, its Market Participants and state policy makers to explore the benefits and costs of dynamic pricing.

II. INTRODUCTION

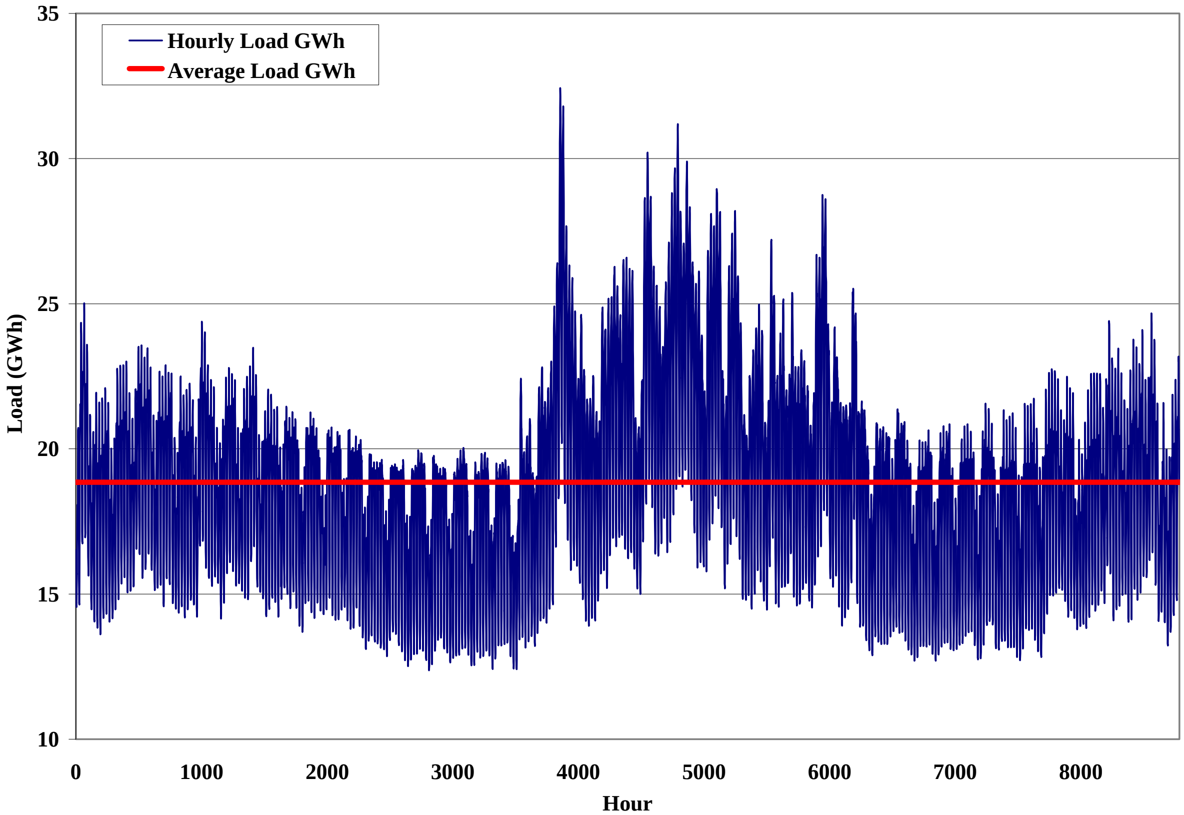
The Brattle Group was retained by the New York Independent System Operator (NYISO) to assist in identifying the potential wholesale market impacts of expanding dynamic pricing in New York. The analysis in this study modeled a hypothetical retail rate construct in which all retail customers face dynamic pricing based on locational-based marginal prices (LBMPs) and capacity costs. To capture the uncertainty inherent in any such assessment, the study considered a range of scenarios to reflect varying assumptions on capacity prices, consumer price elasticity, and enabling technologies. The results of the analysis are intended to inform stakeholders of the likely effects of dynamic pricing on demand, total resource costs, and social welfare. The study is not intended to recommend a particular retail rate design but rather to illustrate the potential impacts of increased levels of price responsive demand.

III. THE CONCEPT OF DYNAMIC PRICING

Since electricity cannot be economically stored in large quantities, it must be generated the instant it is needed in order to balance supply with demand. Electricity demand is highly dynamic. It is shaped by factors that include the economy, weather and the rhythm of life in homes and businesses. In states such as New York, which experience highly variable climate conditions in both seasons, the influence of weather on peak demand can be very significant. While the electric system must be prepared to address peak load conditions, average electricity demand is typically far less than the peak demand. For example, average hourly demand in New York State during 2008 was 18,854 MW, 42 percent lower than the 2008 peak load of 32,432 MW. Hourly NYISO system loads and annual average load for 2008 are depicted in Figure 1 below.

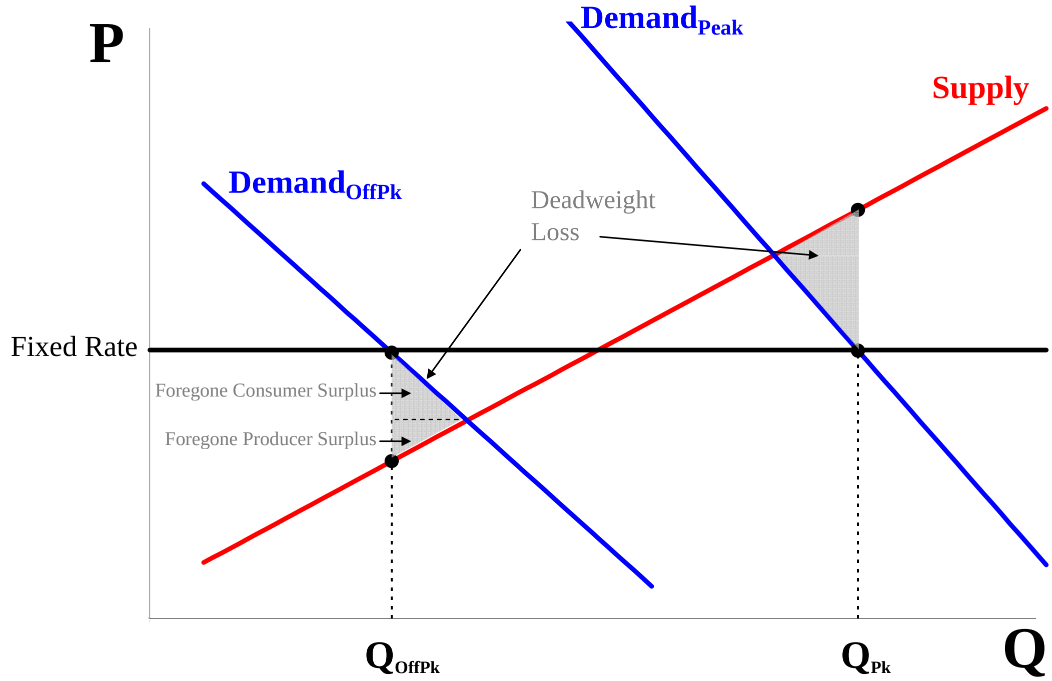
In an average year, the top one percent of hours (roughly 90 hours) of electric demand in New York State accounts for more than 10 percent of system peak demand. Due to the cost of acquiring and maintaining capacity that is seldom needed, the cost to serve peak load is much greater than the average cost over the year. Often, this peak demand is met by seldom-used power plants, often combustion turbines, or older, less efficient and often dirtier plants. In traditional retail rate structures for small customers, where the price does not vary by time of day or time of year, the cost of carrying this seldom used capacity is allocated to customers based on a methodology to estimate of their individual contribution to the peak demand.

Figure 1 Hourly Loads 2008



Flat rates create economic inefficiencies, since they lead to *over-consumption* by customers during the hours of peak demand when the price being paid by customers is lower than the electricity service provider's cost of purchasing that power (and providing capacity during critical hours) and *under-consumption* during the off-peak hours when the price being paid by customers is higher than the cost of generation. The economic value of these inefficiencies can be depicted schematically as the "deadweight loss" triangles between the supply and demand curves shown in Figure 2 below. In low-demand hours, consumers forego consumer surplus and producers forego producer surplus, as shown on the diagram. Conversely, in high-demand hours, customers on fixed rate pricing are over-consuming, resulting in additional deadweight loss. The diagram does not reflect the relative magnitude of the inefficiency in the highest load hours, when incremental demand leads to incremental capacity requirements in addition to energy production.

Figure 2: Economic Inefficiencies Caused by Fixed Retail Rates



By moving to time-of-use (TOU) rates, where rates are varied across various blocks of time based upon a predetermined schedule, these inefficiencies can be reduced. Since the top one percent of the hours, often driven by extreme weather events, cannot be predicted in advance, a more dynamic approach is needed to assign costs to these critical periods.

A more economically efficient rate structure is dynamic pricing, in which the price varies on a day-ahead or hour-ahead basis. Such rates would encourage customers to curtail and/or shift usage during the top one-percent of the hours of the year. By concentrating the cost of peaking capacity in these critical hours, the demand reductions are concentrated in the most valuable periods using the fewest hours. This would have the effect of lowering energy and capacity costs for both the price-responsive customers and, to a lesser extent, non-participating customers.

A recent Federal Energy Regulatory Commission (FERC) study submitted to the U.S. Congress estimated that, at the national level, dynamic pricing and other demand response programs have the potential for reducing peak loads by as much as 20 percent.[5] By eliminating one-fifth of the demand during the critical hours, substantial savings would accrue to customers in the near-term and in the long-term.

[5] The estimate for New York is 16.5 percent. Details can be found in the report, "A National Assessment of Demand Response Potential," Staff Report, June 2009, which can be downloaded from www.ferc.gov.

IV. ANALYTICAL APPROACH

This study was designed to assess the wholesale market impact of a scenario in which all retail customers are moved to dynamic rates. Consumption patterns would certainly change and wholesale markets would be affected. The question is: "In what ways and by how much?" To answer this question, we followed a five-step analytical methodology:

1. *Comparable flat rates and dynamic rates were established* consistent with simulated wholesale market prices for the year 2010 such that consumers would pay the same bills under either rate if their consumption pattern did not change. Wholesale market price projections were derived using the LBMP simulation model and a capacity price estimate reflecting current and projected 2010 market conditions from the *2009 NYISO Load and Capacity Data Report*.[6] Flat rates for representative customer classes in each of four regions (Western Upstate, Eastern Upstate, New York City, Long Island) were synthesized from the annual load-weighted average LBMP (given each class' hourly load shape), plus capacity costs (given each class' coincident peak load), plus non-generation charges included in 2007 retail rates. The hourly-varying dynamic rate was computed as the sum of the hourly LBMP, capacity costs concentrated in "critical" hours only[7] and non-generation charges equivalent to those under the flat rate.[8]

2. *An analysis was conducted on the demand impacts* of switching all customers to dynamic hourly rates using the PRISM model. For each customer class, PRISM calculated hourly demand impacts by applying relevant price elasticities of demand to the difference between the flat rate and the dynamic rate. The demand elasticities are based on empirical analyses in other geographies adjusted to reflect the characteristics of the customer classes in New York State. Thus, PRISM produced a New York-specific price-responsive hourly load profile that is lower in critical hours and other very high-LBMP hours and higher in relatively low-priced hours, compared to the Base Case load profile.

3. *Short-term energy market impacts were estimated* by re-running the wholesale market simulation model using the price responsive hourly demand profiles produced by PRISM. The simulation model provided the effects of dynamic pricing on LBMPs, production cost, and CO_2 emissions.

4. *The value of impacts was calculated* using measures of total resource costs, market-based customer costs, and social welfare.

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[6] Capacity prices for 2010 were assumed to remain at current prices from spot auctions, except in New York City where summer (unforced) capacity prices were assumed to increase to $9.00 per kW-month following the retirement of the Poletti generation unit. This results in annual average (unforced) capacity prices of $27.33/kW-year statewide, $26.85/kW-year for Long Island, and $75.60/kW-year for New York City.

[7] The number of critical hours is 90 for New York City, 50 for Long Island, and 80 for the rest of the state. This parameter is varied across zones and scenarios based on market conditions, such that the reduced load during critical hours is as low as the peak load in non-critical hours, but not lower.

[8] Transmission and distribution and other non-generation charges that are levied on a per-kWh or per-kW basis tend to depress consumption, and they are included in both the flat rates and the dynamic rates in our analysis. However, monthly service charges that do not vary with consumption are not included since they presumably do not affect consumption patterns in either case.

5. *Steps 1-4 were repeated for three alternative scenarios* in which: (1) in-home display devices that provide customers with real-time feedback on their energy usage and costs are deployed along with dynamic pricing. This is termed the "Conservation" case in the study as in-home displays have been proven to induce conservation in about a dozen pilot programs; (2) capacity prices rise to the Net Cost of New Entry (Net CONE), reflecting future market conditions in which there is no longer a surplus of capacity. This is termed the "High Capacity Cost" case;[9] (3) elasticities of demand are approximately twice as high as in the Base Case, reflecting the effects of enabling technologies on customers' ability to shift their consumption.[10] This is termed the "High Elasticity" case in the study.

It is important to note that this approach is limited to estimating near-term impacts. The long-term impacts on market clearing prices for energy and capacity that would need to be included in a multi-year cost-benefit analysis of deploying advanced metering infrastructure (AMI) to support dynamic pricing are less certain. A long-term analysis would need to consider likely effects of dynamic pricing on investment (or retirement of) generation or end-use equipment and also factor in the higher price elasticities of demand that would prevail in the long run.

V. COMPARISON OF DYNAMIC RATES TO FLAT RATES

Many of the larger commercial and industrial customers in New York State are already on dynamic rates. This study assumes that dynamic rates already apply to 15 percent of the peak load in New York City, none of the peak load on Long Island, and 25 percent of peak load in the rest of the state. All other electricity customers in the State were assumed to switch from flat rates to dynamic rates, for the purposes of this study.

It is important to note that the NYISO is not advocating that all customers be required to switch to dynamic pricing. Rather, the analysis is attempting to estimate the wholesale market impacts of a universal dynamic retail rate structure.

Comparable rates were synthesized for the purpose of this analysis based on the methodology described in the "Analytical Approach" section above. Table 1 shows the resulting rates on an annual average basis and how they vary by customer class in each region.[11] Figure 3 illustrates the hourly variation of the dynamic pricing rates compared to the corresponding flat rate for residential customers in New York City.

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[9] The High Capacity Price case reflects recently-filed values for Net CONE: $107.04/kW-year of installed capacity for the System, $143.15 for New York City, and $89.47 for Long Island. See "Proposed NYISO Installed Capacity Curves For Capability Years 2008/2009, 2009/2010, 2010/2011," NYISO, October 5, 2007.

[10] See "Household Response to Dynamic Pricing of Electricity—A Survey of the Experimental Evidence," Ahmad Faruqui and Sanem Sergici, *The Brattle Group*, January 10, 2009, available at http://www. hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf.

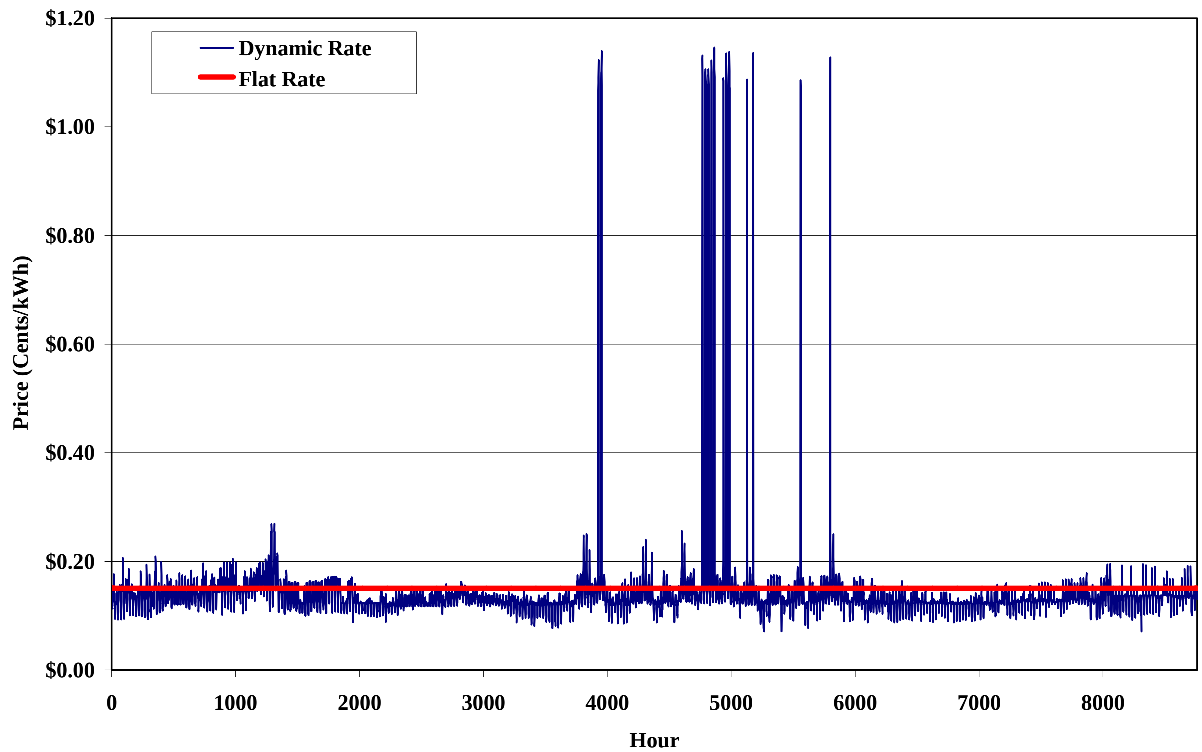
[11] Regions are defined based on their relationship to major transmission constraints. Western Upstate contains Zones A, B, C, D, and E; Eastern Upstate contains Zones F, G, H, and I. These are separated from New York City and Long Island.

Table 1: Flat and Dynamic Rates in the Base Case (Cents/kWh)

Residential Customers	Western Upstate		Eastern Upstate		New York City		Long Island	
	Flat	**Dynamic**	**Flat**	**Dynamic**	**Flat**	**Dynamic**	**Flat**	**Dynamic**
Energy	4.86	4.86	5.31	5.31	6.69	6.69	6.96	6.96
Capacity	0.57	47.90	0.59	48.21	1.31	88.25	0.57	68.18
Other	5.34	5.34	5.34	5.34	7.05	7.05	10.03	10.03
Average Total	10.77	10.77	11.23	11.23	15.05	15.05	17.56	17.56
C&I Customers								
Energy	4.90	4.90	5.35	5.35	6.79	6.79	6.96	6.96
Capacity	0.66	46.85	0.67	47.81	1.56	89.75	0.65	71.98
Other	7.13	7.13	7.13	7.13	8.12	8.12	8.10	8.10
Average Total	12.69	12.69	13.16	13.16	16.47	16.47	15.71	15.71

Note: The capacity component shown under the dynamic rate applies only in critical hours. This component is zero in all other hours. The "Average Total" row reflects the load-weighted average annual average rate, which is the same for the dynamic rate as the flat rate before any change in consumption patterns occur.

Figure 3: Comparison of Flat and Dynamic Rates for Residential Customers in New York City



VI. THE POTENTIAL IMPACT OF DYNAMIC PRICING ON DEMAND

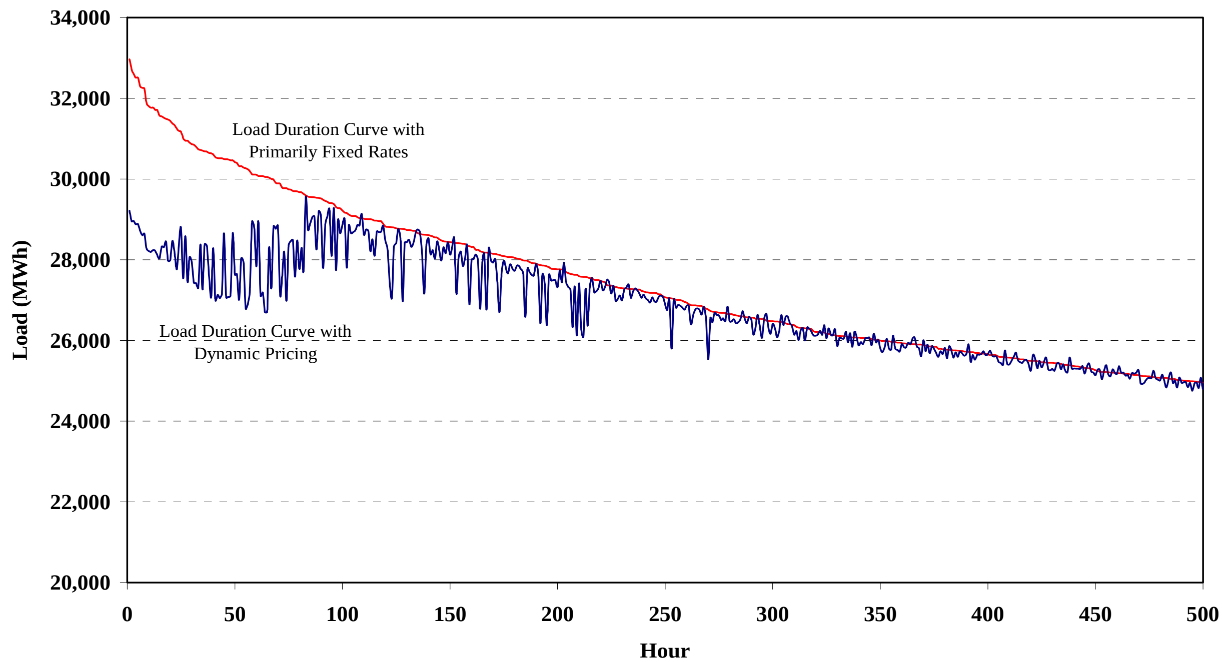
In order to estimate the potential impact of dynamic pricing on demand in New York State, the study applies the price elasticity of demand to estimate impacts. Elasticity measures the percentage drop in demand that occurs when prices increase. The price elasticity of demand has been estimated by customer class in other studies and has been found to be higher for residential customers than for commercial and industrial customers.

If New York State were to transition to dynamic pricing rates, the analysis shows that system peak load could decrease by approximately 10 percent, the New York City peak load would decrease by 13 percent, and the Long Island peak load could decrease by 11 percent under the Base Case assumptions. Should this materialize, it could eliminate the need to install or retain more than 3800 MW of generation capacity representing, for example, 50 peaking generation units of 75 MW each.

Additional insights are obtained when the effect of dynamic pricing is observed at the hourly level. This is shown at the statewide level in Figure 4 for the top 500 hours of the load duration curve. Since the zonal loads are not coincident, the graph has a saw-tooth appearance. Individual zones do not display such a saw-tooth appearance.

While it is clear that dynamic pricing could reduce peak demand, its impact on overall electricity consumption is less clear-cut. Over the course of the entire year, consumption may actually be higher with dynamic prices than fixed rates. This is because dynamic prices are lower than fixed rates in the vast majority of hours, primarily because the dynamic rate has no capacity component during non-critical hours. As a result, total CO_2 emissions appear to increase by approximately 0.5 percent (195,000 metric tons per year), but this is before accounting for the effects of deploying in-home displays. CO_2 emissions decrease by 3.3 percent (1.3 million metric tons per year) in the Conservation case, without accounting for energy efficiency.

Figure 4: Impact of Dynamic Pricing on Hourly Loads



A summary of impacts on peak and average loads in all scenarios appears in Table 2 below.

Table 2: Effects of Dynamic Pricing on Peak and Average Demand

Dynamic Pricing Scenario	**Change in System Peak**		**Change in New York City Peak**		**Change in Long Island Peak**		**Change in Average Load**			
	All Hours		***All Hours***		***All Hours***		***All Hours***		***150 Hours w/Max Δ Load***	
	(MW)	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Base Case	(3,418)	(10%)	(1,514)	(13%)	(590)	(11%)	84	0.4%	(1,897)	(6%)
Conservation	(3,751)	(11%)	(1,514)	(13%)	(604)	(11%)	(288)	(1.5%)	(2,158)	(7%)
High Capacity Price	(4,282)	(13%)	(1,671)	(14%)	(776)	(14%)	176	1.0%	(3,147)	(11%)
High Elasticity	(4,603)	(14%)	(1,961)	(16%)	(779)	(14%)	130	0.7%	(3,606)	(12%)

VII. THE POTENTIAL ECONOMIC BENEFITS OF DYNAMIC PRICING

Several types of economic measures are of interest: total resource costs, wholesale market-based customer costs, and social welfare (consumer surplus and producer surplus). Total resource costs include both the cost of capacity and the variable cost of producing electricity, i.e., fuel, variable operating and maintenance costs, and emissions allowance costs, but we have not included the costs of deploying AMI or the associated operational cost savings. Dynamic pricing affects capacity costs the most because the 10-14 percent reduction in peak consumption substantially reduces the amount of capacity that is needed to reliably meet the peak load. Energy production costs can rise slightly due to increased consumption during non-critical hours. Total resource costs decrease, e.g., by $143 million per year in the Base Case, as shown in Table 3. When conservation brought on by the deployment of in-home displays is included, the savings rises to $352 million per year. Savings are even higher if capacity prices increase.

Table 3: Change in Annual Resource Costs

Dynamic Pricing Scenario	Change in Energy Production Cost		Change in Capacity Cost		Total Change in Resource Cost	
	(Million $)	(%)	(Million $)	(%)	(Million $)	(%)
Base Case	10.6	0.3%	(153.6)	(11%)	(143.0)	(2.6%)
Conservation	(188.2)	(4.5%)	(163.3)	(12%)	(351.5)	(6.3%)
High Capacity Price	60.3	1.4%	(569.0)	(13%)	(508.8)	(6.0%)
High Elasticity	22.5	0.5%	(204.1)	(15%)	(181.6)	(3.3%)

Market-based customer costs include LBMP-based energy costs plus capacity price-based capacity costs, assuming all load is exposed to market prices without long-term contracts, cost-of-service generation, or transmission congestion contracts (TCCs). In the Base Case, market-based customer costs decrease by $171 million per year, as shown in Table 4. Approximately 90 percent of this savings derives from reduced capacity needs, and only 10 percent derives from changes in energy consumption and changes in LBMPs. Thus, the savings depend primarily on capacity prices and not very strongly on changes in LBMPs. In the long run, as capacity prices increase toward “Net CONE,” as represented in the High Capacity Price case, savings would nearly triple. There is additional upside from in-home displays. In the Conservation case, the market-based energy savings is much larger than in the Base Case, partly because 1.9 percent less energy is purchased and partly from the resulting reduction in LBMPs (LBMPs decrease 2.2 more percentage points than in the Base Case while market-based energy costs decrease 4 more percentage points).

Table 4: Change in Annual Market-Based Customer Costs

Dynamic Pricing Scenario	Change in Market Based Energy Costs		Change in Capacity Costs		Total Change in Market Based Customer Costs	
	All Hours		***All Hours***		***All Hours***	
	(Million $)	**(%)**	**(Million $)**	**(%)**	**(Million $)**	**(%)**
Base Case	(17.8)	(0.2%)	(153.6)	(11%)	(171.3)	(1.6%)
Conservation	(415.6)	(4.3%)	(163.3)	(12%)	(578.9)	(5.2%)
High Capacity Price	62.1	0.6%	(569.0)	(13%)	(507.0)	(3.6%)
High Elasticity	(4.5)	(0.0%)	(204.1)	(15%)	(208.6)	(1.9%)

While the net change in energy and capacity costs is a widely used measure of the benefits of dynamic pricing, it may not fully reflect the economic value created by dynamic pricing. Dynamic pricing creates value by avoiding the economic inefficiencies associated with flat rates, thus increasing the sum of consumer surplus and producer surplus, as illustrated in Figure 2. Consumer surplus accounts for changes in costs, but it also accounts for the gain in customer value from increased consumption in most non-critical hours and the loss of customer value associated with reduced consumption in critical hours. For example, customers responding to a dynamic rate of $1.5/kWh instead of a flat rate of $0.15/kWh would eliminate all uses of energy with value less than $1.5/kWh, including fairly high-value uses at $1.4/kWh. The improvement in consumer surplus is only $0.1/kWh.

The net change in consumer surplus was computed using demand curves constructed by linearly extrapolating and interpolating from the two points (each hour) that are provided by PRISM: the initial quantity consumed under the flat rate, and the final quantity consumed under dynamic rates. The calculations account for the fact that transmission and distribution adders cause the dynamic rate to exceed the variable production cost, thus distorting consumption below the "optimal" outcome. Table 5 shows the changes in consumer surplus as the change in customer value minus the change in cost for all hours. The increase in consumer surplus of $162 million to $572 million annually is large. This creates enough value to substantially improve customers' wellbeing and could help offset the initial cost of energy efficiency investments.

Table 5: Change in Consumer Surplus (in $millions per year)

Dynamic Pricing Scenario	Change in Cost	Change in Benefit	Change in Consumer Surplus
Base Case	(169.5)	(7.3)	162.2
Conservation	(578.9)	(7.3)	571.6
High Capacity Price	(504.0)	(170.7)	333.2
High Elasticity	(207.2)	15.6	222.8

Note: The cost figures should theoretically match the market-based customer costs shown in Table 4. The interpolation conducted as part of the consumer surplus calculation causes the two figures to differ slightly.

Producer surplus also changes, primarily because of changes in energy prices. Producer surplus is measured based on the energy margins of all generating units in the energy market simulations and is shown in Table 6. The producer surplus decreased the most in the Conservation case, by $168 million per year, as customers reduce their consumption and LBMPs decrease. Producer surplus does not decrease in the High Capacity Price case because the customers' non-critical hour rate reduction is the largest (due to the lack of high capacity charges relative to the fixed rate), resulting in increased consumption and LBMPs in those hours.

Table 6: Annual Net Change in Social Surplus (in $millions per year)

Dynamic Pricing Scenario	Change in Producer Surplus	Change in Consumer Surplus	Net Change in Social Surplus
Base Case	(21.5)	162.2	140.7
Conservation	(167.9)	571.6	403.8
High Capacity Price	0.8	333.2	334.0
High Elasticity	(7.4)	222.8	215.5

VIII. CONCLUSION

This study has found that dynamic pricing can provide substantial benefits in New York State by reducing total resource costs, lowering customer market costs, and improving economic efficiency. With estimated market-based cost savings in the range of $171 million to $579 million per year, the benefits to electric consumers can be significant, especially when technology serves to facilitate demand response and energy conservation.

Given the magnitude of these potential wholesale market benefits serious consideration should be given to further evaluation of the widespread deployment of retail dynamic pricing. The NYISO looks forward to working with its market participants, as well as policy makers and regulators in the state and federal governments to explore ways to further facilitate end-user participation in its markets.