Realizing Real-Time Pricing's Promise: What CHP Offers MHP?

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ABSTRACT

Real-time pricing (RTP) programs provide economic incentives for customers to reduce energy consumption during peak hours. Several states have created RTP rate structures – voluntary and mandatory – on various categories of customers, usually industrial, larger commercial and institutional customers. In 2006, New York State imposed mandatory hourly pricing (MHP) for all distribution utilities on a select group of customers initially ranging in size from 1,000 kW maximum peak demand to 1,500 kW maximum peak demand, depending upon the utility. The maximum peak demand level triggering mandatory hourly pricing was scheduled to drop over time, so that by Spring 2011 all customers with maximum peak demand levels in the range of 300 kW to 500 kW will be subject to MHP. At these demand levels, MHP will be affecting a much broader group of customers statewide. Evidence suggests that customers are not changing behavior in reaction to price, but are migrating to providers who offer a flat pricing structure (though in NY the provider still faces the MHP rate). Con Edison's 2009 MHP Evaluation Report cites that affected customers were actually using more on-peak energy in 2008 under the MHP program than they were in 2006, prior to the MHP program. This paper summarizes the status of MHP in New York. Based on empirical modeling of the potential value created by sites strategically employing combined heat and power (CHP) under an MHP regime, argues that CHP can significantly improve the performance of MHP in New York and deliver savings to customers. Results were particularly favorable for commercial customers employing CHP in Manhattan where the spread of prices was greater than it was in upstate New York.

Introduction

Dynamic pricing programs are designed to elicit specific customer responses to varying market prices as an efficient way of reducing demand for electric power during peak hours. Because a small proportion of the hours of the year, the highest demand hours, have a disproportionate impact on prices and system requirements, lowering demand at a very small proportion of hours can make a significant difference in energy costs. Policymakers commonly assume that customers are able to adjust – at least partially – their hourly, daily, or seasonal power-consumption patterns to respond to price variations. Possible adjustments customers are commonly assumed to be able to make include:

- Shifting production schedules from higher priced to lower priced hours,
- Increasing building cooling temperatures temporarily to higher set points,
- Taking certain services off-line temporarily (e.g. lighting, elevators), and
- Investing in onsite generation and cogeneration (Combined Heat and Power or "CHP")

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There is substantial evidence that real-time pricing (RTP)[2] programs can reduce peak demand and overall customer prices by sending consumers accurate market signals. In particular, the following programs are considered to have – at least partially – demonstrated that RTP can achieve desired policy outcomes:

- California Statewide Pricing Pilot Program (2003-2004)
- Baltimore Gas and Electric Company (2008)
- Community Energy Cooperative (2003-2006)[3]

But, RTP programs have not always performed as planned. For example, in 2002, Puget Sound Energy, a local energy utility serving customers in Washington State's Puget Sound region, abandoned a mandatory time-of-use (TOU) pricing program for all residential customers after customer bills began rising and an analysis of the program's impact showed negative cost benefit. The principal problem with the Puget Sound program was that the difference between peak and off-peak power prices was insufficient to produce savings, when behavior changed, to offset the costs of the new meters. In New York, efforts to push for Time of Use pricing triggered a backlash that led to state legislation prohibiting "mandatory" time-based pricing in the residential sector. Similarly, high prices and unhappy customers convinced Maine's Public Utilities Commission to drop a mandatory TOU rate for large customers a few years ago. (Alexander 2008).

There is evidence that dynamic-pricing programs perform poorly if customers have few options for responding to high prices. RTP programs that depend exclusively on customers shifting load from peak hours to off-peak hours or shedding load when prices are high are unlikely to deliver the desired policy outcomes. Barring a radical reversal of current trends, New York's efforts to extend RTP to large customers in the commercial sector are likely to become yet another cautionary tale that dynamic pricing alone may not reduce overall consumption or lower annual bills for customers (Faruqui 2006).

While various benefits are supposed to flow from RTP, the *sine qua non* of a successful RTP program is a reduction in aggregate load served by the power grid during peak demand. Based on this metric, New York's MHP program for large customers has failed. This paper will summarize the principal customer response strategies to MHP. The paper will highlight the findings of a modeling exercise to show the substantial synergies between MHP and CHP and demonstrate how wider adoption of CHP could improve the performance of MHP in New York.

RTP: From Theory to Practice

Dynamic pricing pins the price of electricity over the course of the day to prices in the "spot" or "day ahead" wholesale markets.[4] The theory is that customers can shift usage or

[2] This paper uses the following ways of describing dynamic-pricing programs interchangeably: Mandatory Hourly Pricing, Time of Use (TOU) Rates, Critical Peak Pricing and Real Time Pricing. While TOU rate structures are not truly "dynamic" since they do not vary according to market conditions, they do reflect the higher cost of supply during peak periods and lower cost during off-peak periods. Viewing TOU rates along the continuum of rate structures between traditional flat-pricing rates s and truly dynamic prices, we elected to include TOU under this expansive definition of "dynamic pricing."

[3] Community Energy conducted a pilot program in Commonwealth Edison's service territory in northern Illinois between 2003 and 2006, which then became an official Commonwealth Edison program in 2007.

reduce usage according to their “sensitivity to price.” In particular, consumers will shift peak consumption to off-peak consumption, which will limit the ability of suppliers to increase spot and long-term market-clearing prices above their equilibrium level (Ruff 2002). RTP proponents have claimed that price signals are more efficient than pay-for-performance demand response programs because incentives paid in excess of the bill savings realized by avoiding electricity consumption in high-priced hours amount to a subsidy (Goldman and Hopper 2004).

The rationale for imposing RTP rates derives from the economic theory of the firm. This theory stands for the following proposition: firms minimize the cost of producing a specific output by finding the least cost inputs available (Moezzi 2004). Electricity is among the most basic inputs businesses need to conduct normal operations. Theoretically, businesses are supposed to allocate use of electricity according to its value as an input for each hour of the day. Businesses should use less electricity during high-priced hours of the day and more during the low-priced hours to meet the day’s expected level of business. In other words, the theory of the firm assumes that businesses have options that permit a shift of energy use from peak to off-peak hours over the course of a day according to varying power prices during that day.

MHP in the Empire State

In 2005, the New York State Public Service Commission (PSC) decided to accelerate the introduction of Mandatory Hourly Pricing (MHP) for all utility customers in certain peak demand size ranges. The price of electricity had escalated to record highs in New York in the aftermath of Hurricane Katrina, which devastated large parts of the Gulf Coast’s natural gas infrastructure. Like other states in the Northeast, New York relies heavily on expensive gas-fired generators for satisfying peak demand. Since these generators typically operate “on the margin” during periods of peak demand, they commonly set power prices.

The PSC implemented MHP to stabilize and ultimately lower volatile power prices by reducing peak demand levels. The logic ran like this: higher prices during peak demand will encourage customers to avoid using power during peak hours by shifting consumption to off-peak hours whenever possible. If there is less peak demand, the highest-priced generators will need to operate less, decreasing the costs of producing power and – in turn – the average price paid for consuming power by people served on the system. To this end, the PSC required New York’s principal utilities to move specific categories of large customers from conventional to dynamic-pricing rates in scheduled increments. The PSC’s MHP program would ultimately expose more than 2,200 non-residential customers representing 5,300 MW of load to day-ahead hourly market prices for electricity. The PSC estimated that customers exposed to RTP would respond to high prices during peak demand by shifting as much as 750 MW worth of consumption to off-peak hours.

[4] New York's MHP program pins hourly rates to prices in the Day Ahead Market rather than “real-time” market conditions.

MHP: Progress to Date

"Con Edison fully agrees with the P.S.C.'s conclusion that accurate price signals will lead to reduced peak usage, which will, in turn, mitigate peak-period prices, increase peak-period reliability and reduce New York state's dependence on natural gas-fueled generation, as well as greenhouse gas emissions."

-Bob McGee, Consolidated Edison

Research has found that most of the load reduction during peak-demand periods results from a fraction of all RTP program participants (Goldman 2006). While some customers adjusted consumption patterns to accommodate price signals, the majority of customers haven't appreciably changed how they consume power in reaction to price (Hopper 2006). Ironically, rather than decreasing consumption during periods of peak demand, MHP customers actually increased energy consumption in on-peak periods and decreased consumption in off-peak periods between 2006 and 2008. Specifically, "off-peak energy use for the total group of MHP customers decreased from 54% of the total annual energy use in 2006 to 52% in 2008." In other words, MHP has not reduced peak demand in any meaningful sense. And yet, the bills paid by customers for power under MHP have risen. The bottom line: MHP has not delivered the policy results it promised. Apparently customers cannot or will not shift load as readily as policymakers seemed to suspect when they instituted MHP. To the extent MHP depends exclusively on load shifting or shedding, it is likely dead-on-arrival.

Response Strategies To MHP Have Not Delivered Anticipated Results

Over the past year, the New York utilities responsible for implementing MHP in their respective service territories have released detailed reports on the MHP program's performance to date for the PSC. The results are not promising.

Price Hedging Strategy

Rather than shifting or shedding load, the principal response strategy for customers receiving service under MHP rates has been to enter power-supply contracts with third-party ESCOs that limit their exposure to RTP. These power-supply contracts commonly include fixed or indexed price structures. There are also several financial derivatives offered in the retail market by ESCOs.

Roughly 100 of 790 eligible buildings use the program now and 330 of a potential 1,200 have signed up to begin in May 2011 (Appelbaum 2010). Many of the customers in New York City that are now receiving service under MHP – or that soon will be receiving service under MHP rates – have purchased fixed-rate contracts from energy services companies (ESCOs). The fixed-rate contracts customers include TOU and flat-rate pricing, typically applying to all of the customer's usage. Indexed rates were linked to the NYISO day-ahead market or some other reference prices. Reported indexed products typically provided a discount relative to the default rate (Hopper).

A common hedging product offered in the retail market is the so-called ''block-and-index'' contract. Under this arrangement, customers willing to expose a portion of their load to hour hourly market prices contract for blocks of load at a fixed $/kWh price and pay hourly spot market prices for usage in each hour that exceeds the block level (Barbose 2006).

"When asked about factors driving customer demand for hourly priced supply contracts, retail suppliers indicated that customers' ability and willingness to respond to hourly prices was typically not a significant driver. Suppliers offered several alternative explanations: (1) some customers are looking for a guaranteed savings off the default RTP rate; (2) some are simply riding the market, waiting until the time is right to lock in a fixed-price contract; and (3) some have decided that the premium for a fixed-price, full requirements service is greater than the value they place on the price certainty such contracts provide."

Lease Conventions Encouraging Flat-Rates over MHP

The structure of commercial leases in New York may partially explain the race to flat-price contracts triggered by MHP. Commercial office leases usually allocate utility expenses between a building owner and its tenants using formulas, which vary widely between owners and even among different tenants in the same building. There are three principal types of leases for purposes of allocating expenses between building owners and tenants in the U.S. office sector:

- Net leases – tenant pays for all expenses
- Gross leases – building owner pays for all expenses
- Fixed-base leases – building owner and tenant pay expenses

In New York City, two types of leases prevail in the market for commercial office buildings: the triple-net lease and the gross lease. In a triple-net lease, the tenant pays for all of the building's expenses—maintenance, taxes, operating expenses and so forth. In a gross lease, the tenant only pays rent for the space they use and the landlord is responsible for everything else.

Manhattan office buildings commonly use a "modified gross lease" structure, which makes the tenant responsible for base rent, electricity and the tenant's respective share of any increases in operating expenses and taxes. These increases in operating expenses or taxes are called "Additional Rent" in the parlance of commercial office leasing. Commercial tenants agree to pay for electricity in a lease agreement in one of three ways:

- **Direct meter:** Tenant pays the utility directly for amount of electricity used, which is determined by utility meter installed for individual tenant.
- **Sub-meter**: Landlord purchases the power in bulk from the local utility. Tenants are billed for their actual use based on individual electric meters installed on the circuits of each tenant. Tenants are charged a markup on the price paid by the landlord, which reflects the cost of the administration of the sub meter.
- **Rent inclusion**: Landlord charges tenant a fixed price per square footage annually, which is not determined by how much electricity is used. Many leases make the rent inclusion "subject to survey." This means, that at any time, the landlord can send a company into the tenant's space to survey the amount of electricity the tenant is actually using. If tenants are found to be using more electricity per square foot than they are paying for, the landlord may raise the tenant's electricity charge accordingly. Contesting this increase is expensive.

Load Shedding

Most of the customers who were responsive chose to reduce usage or shed load. While large customers frequently have access to sophisticated energy management technologies that should theoretically enhance their responsive to price signals, previous studies have “found no meaningful statistical relationships between use of these technologies and price response” (Goldman 2005). Customers commonly use these technologies for identifying and implementing energy savings initiatives but do not appear to use them to respond to real-time market conditions.

Load Shifting

Less than 25 percent of customers who have moved to MHP rates in New York said they were able to shift their operational load from periods of peak demand to off-peak demand. Inflexible labor schedules were the principal reason cited by customers for why they were unable to shift load from their normally scheduled time to a lower cost period, but it was hardly the only obstacle preventing them from responding to RTP. Many customers claimed that the cost of responding to real-time pricing exceeded the potential savings. Other customers lacked sufficient personnel and related resources for monitoring – and responding to – market prices.

CHP May Provide Customer Flexibility in Responding to Hourly Prices

Customers using CHP can achieve the operational savings MHP makes possible without shifting production schedules, adjusting comfort levels or reducing productivity. Recent modeling results indicate that strategically operating a CHP system under an MHP regime can add significant value to the capital investment, in some instances markedly shortening payback periods and return on capital.

By pinning prices to hourly market prices, MHP creates opportunities for CHP operators to optimize their electricity purchases by using less purchased electricity when prices are high and more when prices are low. CHP systems can save money for facilities if they operate when electricity prices are highest and using grid-based electricity when the cost of doing so is less than the avoided costs of running the CHP system. By operating CHP more during peak hours, and less during off-peak hours, within the parameters of the host site’s electric and thermal load characteristics, MHP can significantly enhance the rate of return for investments in CHP.

Customers receiving service under MHP rates have responded to higher prices primarily by shedding load during peak hours. A small few have shifted load from peak to off-peak hours while a small group have followed a third strategy: self-generation. In previous RTP programs, the most price responsive customers have had onsite generation installed. In Duke Power’s voluntary RTP program, seven of the 12 most responsive customers used on-site generation (Schwarz 2002). Niagara Mohawk's SC-3A customers who responded to hourly prices using onsite generation reported significant load response. In 2005, a survey of customers in Niagara Mohawk's RTP program, “the most common interviewee response to the question of what would best allow their company to be more price-responsive was a version of ‘create more favorable conditions for use of CHP or other on-site generation’” (Moezzi 2008).

Table 1. Facility Attribute Considerations

Attributes	Good Characteristics	Bad Characteristics
Time of Usage	Operations highly concentrated in peak hours	Primary operations during off-peak hours
Electrical Load	Uniform load shape and high usage of CHP system	Erratic load shape
Power Prices	Wide range of prices between peak and off-peak times	Narrow range of prices between peak and off-peak times
Thermal Load	High coincidence between electrical and thermal demands	Low coincidence between electrical and thermal demands

MHP favors CHP systems used most intensely during periods of peak demand. Facilities that have substantial power and thermal loads during high priced hours can leverage CHP very effectively under MHP. Table 1 describes attributes that lead to better (or poorer) outcomes for a prospective CHP system operating under an MHP regime.

Modeling Economic Return on CHP under Mandatory Hourly Pricing

MHP presents a new opportunity to strategically operate the CHP system to save money when electricity prices are highest, and conversely to use grid-provided electricity when the cost of doing so is less than the avoided costs of running the CHP system.

To quantify the impact of CHP on the economics of operating a CHP system a set of representative CHP applications were selected for downstate and upstate New York. A six-story, 550,000 square-foot hospital and a ten-floor, 300,000 square-foot hotel were selected to represent two typical types of commercial building operation. The hospitals had a peak maximum demand of 2,200 kW and minimum loads just under 1,000 kW. The hotels had an annual peak demand of 825 kW and minimum demand of 260 kW. The two representative applications were located in Manhattan and in Syracuse, NY.

Hourly electric and thermal requirements for each of the building types in the two locations were developed primarily using the U.S. Department of Energy's EQuest software. Applying typical equipment energy requirements for each building type, modified by geographic factors (heating and cooling degree days), hourly electric and thermal energy demands (in kW electric and Btu-hour gas) and energy consumption (kWh's and Btu's) were created. Hourly electric demand is required as an input for the rate analysis, which includes a daily as-used demand charge that is assessed in the case of a site operating a CHP system. A monthly maximum demand charge is assessed in the case of a site that does not operate a CHP system.

A monthly gas and electric bill for each site was prepared by applying unit gas rates to the monthly gas consumption and kW demand charges and kWh rates to the monthly electric demand and consumption. The baseline is a standard separate heat and power configuration whereby the site purchases all electricity requirements from the distribution utility under the applicable tariff.[5] Space heating and water heating are provided by a central gas-fired boiler. Air conditioning is provided by an electrically driven chilled water system.

Against this baseline we compare two modes of CHP operation. The CHP systems are sized to utilize as much of the thermal generation as feasible. Sizing in the case of the CHP

[5] Applicable rates were National Grid SC 3-a for the Upstate hospital, and SC 3 for the hotel. Downstate rates were Consolidated Edison's SC 9 for both the hospital and the hotel.

system without cooling was designed to use about 80% of the available thermal energy from generation. Sizing of the CHP system with cooling utilized 100% of the thermal energy from generation.

One CHP operating strategy is to run as many hours of the year as available,[6] in what was referred to as a *"Continuous Operation Model*". In this scenario the CHP system is run for as many hours of the year as its availability factor permits. The system is operating for all hours except for those times when it is down for scheduled maintenance or is out of service due to an unplanned outage.[7]

An alternative strategy was designed to take advantage of the availability of the hourly pricing regime. In this mode of operation a decision rule was imposed that compares the value of running CHP and displacing a portion of gas purchases in any non-peak hour[8] against the cost of purchasing all electric power requirements from the grid and all gas from the gas distribution company. This mode of operation was referred to as the *"Economic Dispatch Model"*.

The decision rule applied in the study assumed that sites would elect to run during all peak hours, as defined in the utility tariff, to avoid incurring additional demand charges, which are increased for facilities that shut down during periods of peak demand. To determine whether the CHP system would operate during an off-peak hour, the decision rule stated that if the operating cost of the CHP system (CHP_{Fuel} + $CHP_{O\&M}$ + $Supplementary_{Electric\&Gas}$) was less than electricity and gas cost at full hourly loads, then the CHP system will operate; otherwise, it will not. This decision rule is illustrated by the flowchart

The analysis considered a dozen different cases for using CHP systems in hospitals and hotels under two distinct operating strategies: continuous operation and economic dispatch. These CHP model cases are summarized in Table 2.

Table 2. CHP Operating Strategies Modeled

Facility Features	Downstate Cases		Upstate Cases	
	Continuous	***Dispatch***	***Continuous***	***Dispatch***
Hospital No Cooling	(500 kW)	(500 kW)	(500 kW)	(500 kW)
Hospital w/ Cooling	(1,000 kW)	(1,000 kW)	(1,000 kW)	(1,000 kW)
Hotel No Cooling	(300 kW)	(300 kW)	(300 kW)	(300 kW)

Sites running in "continuous operation" operate all hours of the year except for scheduled maintenance and forced outages. On the contrary, sites running in "economic dispatch" mode decide to operate based a decision rule based on hourly electricity prices on hourly electricity prices.

[6] In this mode of operation the CHP ran all hours of the year, except for planned maintenance hours and random experiences of unplanned outage hours.
[7] Forced outages are modeled as an event randomly distributed across the year.
[8] The decision rule only was applied to non-peak hours. For all peak hours of the year, the CHP system was assumed to run under both types of operating strategies.

Value Created by MHP for Sites Running CHP

In every hour of the year, for each building type and geographic location we create an *hourly operating cost* incurred by running in each of the following modes:

1. Baseline Operation[9]
2. Continuous Operation
3. Economic Dispatch

We sum the total annual cost of operation based on 2007 data for each of the three modes of operation. The difference between the annual cost of Baseline and the two CHP operation modes is the savings that is attributable to CHP. The net savings due to CHP is calculate for each of the twelve cases; the 6 cases running CHP in Continuous Operation mode and the six cases running CHP in Economic Dispatch mode.

Table 3: Net CHP Savings for 12 Modeled Scenarios

Facility and Location	Net CHP Savings	
	Economic Dispatch	Continuous Operation
Downstate Hospital	$277,155	$232,972
Downstate Hospital w/Cooling	$494,167	$341,723
Upstate Hospital	$133,837	$125,053
Upstate Hospital w/Cooling	$233,732	$179,715
Downstate Hotel	$83,544	$38,317
Upstate Hotel	$105,810	$98,408

This study finds that economic value for CHP host facilities is created when facility operators can take advantage of MHP. The project team compared continuous operation of CHP with a strategy that employs CHP strategically in response to hourly price signals. The difference between the annual cost of CHP Continuous Operation mode and the cost of CHP Economic Dispatch is referred to as the "value created by economic dispatch".

[9] Baseline operation refers to purchasing all electric requirements from the grid and all thermal requirements from the natural gas local distribution company.

Table 4: Net Value Created by MHP for Facilities Using CHP

	Net CHP Savings		Value Created by MHP	% Increase in Savings
	Economic Dispatch	Continuous Operation		
Downstate Hospital	$277,155	$232,972	$44,183	19%
Downstate Hospital w/Cooling	$494,167	$341,723	$152,444	45%
Upstate Hospital	$133,837	$125,053	$8,784	7%
Upstate Hospital w/Cooling	$233,732	$179,715	$54,017	30%
Downstate Hotel	$83,544	$38,317	$45,227	118%
Upstate Hotel	$105,810	$98,408	$7,403	8%

The additional value created was as much as $152,444 on an absolute basis.[10] When comparing the increase in value on a percentage basis, that is, net annual CHP savings with economic dispatch divided by net savings under continuous operation, the downstate hotel case realizes more than a doubling of savings with economic dispatch. These results are shown in Table 4.

In general, the additional value created is markedly greater for the downstate region than for the upstate region. In large part the reason for this additional value is due to the significantly concentration of higher hourly prices in the Con Ed territory. Table 5, below, displays mandatory hourly prices for the year 2007, distributed across the percentage of hours of the year in which a particular price level was exceeded.

Table 5: MHP Distribution by Percentage of Hours in the Year (Deciles)

National Grid Price ($/MWH) Exceeded	Con Ed Price ($/MWH) Exceeded	% of All Hours
$221.32	$245.02	Maximum hour
$106.84	$126.55	10% of hours
$94.60	$114.11	20% of hours
$82.82	$106.89	30% of hours
$74.31	$100.18	40% of hours
$68.18	$93.35	50% of hours
$62.34	$86.27	60% of hours
$55.90	$77.18	70% of hours
$49.57	$66.51	80% of hours
$42.67	$57.24	90% of hours
$0.00	$36.68	Minimum hour

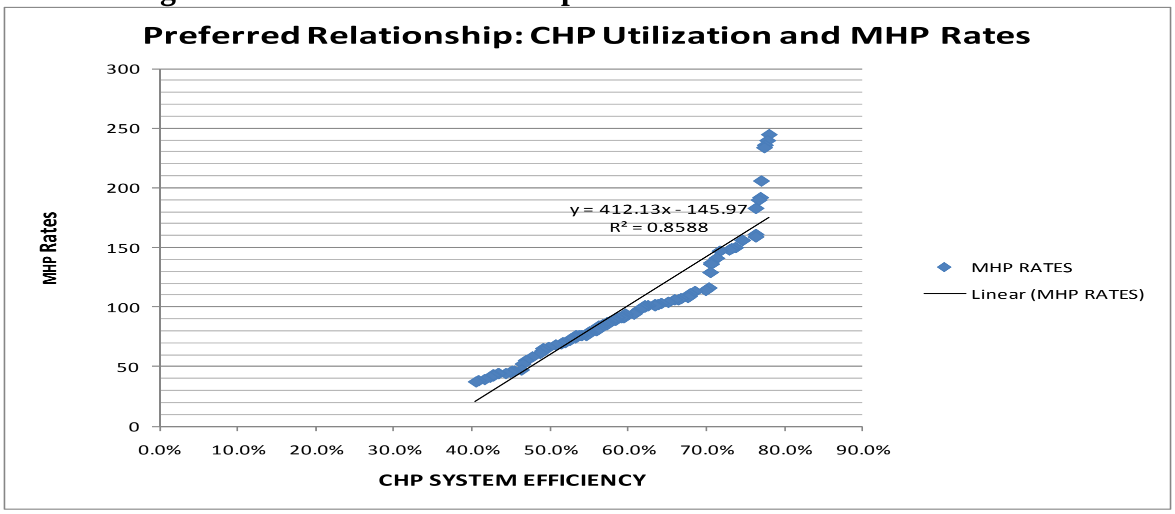
Ideal Circumstances for CHP Under MHP Regime

The efficiency and the cost effectiveness of a CHP system depends in large part on the extent to which the thermal output can be utilized provide the hot water, space heating, process heating or cooling needs of one or more facilities. When a facility's demand for electricity and

[10] The downstate hospital with cooling scenario yielded the greatest absolute value of incremental savings under an MHP regime for all of scenarios modeled.

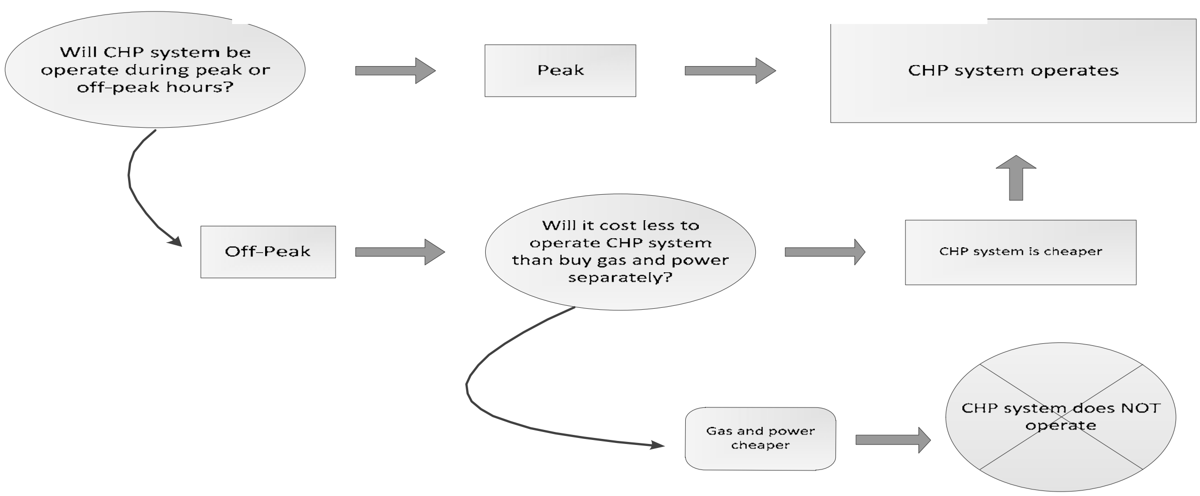
thermal energy (e.g., steam, hot water or space heating) coincide to a significant degree, the CHP system can operate at its highest efficiency, thus creating the most value for the facility.

Figure 1: Preferred Relationship: CHP Utilization and MHP Rates



In ideal circumstances, the facility needs the most heat and power when grid-based power costs the most and needs very little or no heat when grid-based power costs the least. This

Figure 2 Decision Rule for CHP Under MHP



correlation is commonly called "peak coincidence." To the extent facilities need the most electric and thermal energy during peak-demand hours, they stand to gain significantly from the introduction of a MHP regime. Figure 1 displays the optimal relationship between CHP system efficiency and MHP rates. In this ideal case, the intensity of usage of the CHP system is greatest, and the CHP system efficiencies are at their highest, when MHP prices are at their peaks. The value of CHP under an MHP regime diminishes as this correlation weakens. If the hours when the facility's peak coincident electric and thermal demands occur at the low-priced hours, then operating a CHP system under an MHP regime becomes much less attractive as compared with operating under a flat pricing structure. In other words, since CHP should be operated in hours when it can serve both on-site thermal and on-site electrical demand, the site will benefit if those hours also correlate with particularly expensive MHP energy that the site can avoid purchasing.

Strategic Use of CHP under an RTP Regime Can Markedly Improve Value

For the types of cases we modeled, the existence of mandatory hourly pricing has favorable implications for the economics of operation CHP systems in New York State. The results described indicate that for the types of facilities modeled, in the regions selected, with the data applicable to the selected year (2007), the existence of MHP created additional value when compared with continuous operation of CHP systems. The ability to access cheaper electricity during lower load hours of the day creates net benefits for a system. This value has been expressed in terms of the net annual total reduction in CHP facility operating cost when comparing a system that uses an economic dispatch strategy with a continuously operating CHP system. This result is dependent upon the particular daily, weekly and seasonal electric and thermal loads of the applications selected for study.

Conclusion

Exposing customers to hourly, daily and seasonal fluctuations in price has long been proposed as an efficient means of lowering energy costs and improving the productivity of the electric power generation, transmission and distribution system. The theory is that customers have a menu of options that permit them to adapt to price changes on an hourly or seasonal basis. This paper reviews a body of evidence suggesting that RTP pricing regimes have not yet yielded benefits promised. Customers may face limited options for responding to price. If the only options are to shed load this may result in a loss of productivity that the customer either cannot bear, or values less than the energy savings. CHP offers an alternative response that does not require a diminution of comfort or productivity at the facility. In all of the cases modeled, strategically operating a CHP system under an MHP regime brings additional value to the site. The objective of RTP is to improve the productivity of the electric power system - from generation to the end use customer by lowering demand in the most costly hours. There is a strong coincidence of interest of a CHP host using electric and thermal energy most intensively during peak hours with the RTP objective of reducing demand at the super-peak. At peak demand times prices rise significantly. A relatively few hours of high demand per year exacts a disproportionate share of total system. Reducing demand in those hours yields significant productivity benefits. The profitability of the CHP system improves in direct relation to the increase in avoided hourly prices, when the CHP system's efficiency is correlated with high priced hours. We conclude that CHP, where technically feasible and economically viable provides a mechanism for achieving this objective while simultaneously delivering significant economic value for sites employing CHP.

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