Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff

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ABSTRACT

Real-time pricing (RTP) is advocated as the most economically efficient way to invoke demand response (DR) benefits, yet actual customer experience is limited and thinly documented. This study examines the experience of 130 large (over 2 MW) industrial, commercial and institutional customers at Niagara Mohawk Power Corporation that have faced day-ahead electricity market prices as their default tariff since 1998. It is the first study of large customer response to RTP in the context of retail competition. Through a survey and interviews, we examine how customers adapted to RTP (their satisfaction, hedging choices, adoption of DR-enabling technologies and response capability), and we combined survey information with customer billing data to quantify price response. We find that customers are relatively satisfied. In 2003, 50-55% were exposed to RTP; many say they'd prefer to hedge but attractively priced options are rare. Only 45% of survey respondents have installed DR-enabling technologies since 1998. 54% indicated they were not price responsive at all; of the rest, most employ "low-tech" curtailment strategies and do not reschedule usage. Average price response estimates are modest: the overall substitution elasticity is 0.14. Surprisingly, government/educational customers display the highest response (0.30); industrial response is similar to past research findings (0.11) and commercial customers are least responsive (0.00). New York Independent System Operator DR programs significantly boost industrial participants' price response when events are called. Default RTP does deliver modest DR benefits, but is best viewed as part of a portfolio of DR options.

Introduction

The experience of the past few years has demonstrated the propensity for extreme volatility in restructured electricity markets in which end users are not participants. Thus, there is increasing interest in policies, programs and tariffs that encourage demand response (DR) to help discipline wholesale electricity markets. A range of options have emerged, from utility- or ISO-sponsored DR programs that provide financial incentives for customers to curtail load at critical times to dynamic pricing tariffs designed to reflect variations in wholesale market costs better than the fixed-rate tariffs the majority of end users face.

Proponents of real-time pricing (RTP), a tariff option in which customers pay hourly-varying prices (usually communicated day-ahead) for electricity, argue based on evidence from conceptual studies and market simulations that if a sufficient number of consumers are exposed to and adjust their demand in response to wholesale electricity market prices, the resulting load reductions will limit the ability of suppliers to increase spot and long-term market-clearing prices above their equilibrium level (Borenstein 2002; Ruff 2002). Further, they argue that such price inducements are more economically efficient than pay-for-performance DR programs because incentives paid in excess of the bill savings realized by foregoing electricity usage in high-priced hours amount to a subsidy. However, this assumes that RTP actually does deliver adequate demand response benefits. Actual customer experience with RTP is limited and thinly documented and as a result adaptive behaviors are not well understood.[1]

Large customers are often targeted for RTP implementation because curtailment opportunities are assumed to be greater due to the size of their loads and the additional metering requirements to implement RTP are often negligible. A few empirical studies of large customer RTP response have shown modest results for most customers, with a few very price-responsive customers providing most of the aggregate response (Herriges et al. 1993, Schwarz et al. 2002). However, these studies examined response to voluntary RTP programs at regulated utilities (with no retail competition) in which the tariff design included a built-in hedge and, in many cases, no additional inducements to curtail were offered (e.g., pay-for-performance DR programs).[2] Furthermore, the researchers had limited access to information on customer characteristics so were unable to explore in detail the factors that influence how customers respond.

This study fills many of these gaps. It is the first empirical study of a large customer RTP tariff implemented as the default tariff in the context of retail competition. It is also unique in combining empirical modeling with information gathered through customer market research. This enables refined estimates of price response that tease out the impact of customer-specific factors such as ISO DR program participation, energy intensity, timing of peak usage and enabling technology investments. It also provides contextual information about customer attitudes and adaptation, proclivity to hedge price risk (through fixed-rate supply contracts or financial hedges), and how customers respond – useful information for policymakers considering RTP implementation for large customers in states with restructuring.

We begin by providing background on Niagara Mohawk Power Corporation's (NMPC) RTP tariff that is the focus of our study and describing data sources. We then present results from the customer survey – customer education and acceptance, hedging options and the role of enabling technologies. Next, we present price response results, including customers' self-assessment of their response capabilities, empirical price response results, and estimated aggregate demand response potential. Finally we discuss key results and implications for policymakers interested in RTP and demand response.

RTP at Niagara Mohawk

In October 1998, with the commencement of retail access in New York, NMPC replaced the existing time-of-use (TOU) tariff for large customers (>2MW) served under the "SC-3A" class with an RTP rate design. This new default SC-3A service recovers fixed costs (e.g.,

[1] While there are a growing number of reports of significant price response, only a few comprehensive and transparent analyses are publicly available; the most recent are those of Schwarz et al (2002) and Charles Rivers Associates (2004).

[2] This tariff design, called "two-part RTP", consists of a customer baseline load (CBL) billed at the customer's otherwise applicable time-of-use tariff rate (the hedge) with only marginal usage (deviations in actual usage from the CBL) subject to hourly-varying prices.

transmission and distribution) largely through demand charges and prices electric commodity at hourly-varying prices indexed to the NYISO day-ahead market.[3]

The NMPC restructuring plan included an alternative option for commodity service (called Option 2) whereby customers could sign up for a TOU-style fixed rate offered by NMPC for up to five years on a take-or-pay basis. However, this alternative was offered only on a one-time basis in the fall of 1998, just prior to the opening of the retail market, and required that customers nominate monthly peak and off-peak demand blocks (at 100% load factor) for a five-year period.[4] SC-3A customers could also elect to purchase their electric commodity from competitive retail suppliers (referred to as ESCOs in New York), some of whom offered hedged supply contracts and/or financial hedging products.

Since 2001, the New York Independent System Operator (NYISO) has offered customers throughout New York state the opportunity to participate in its DR programs, which provide incentives to curtail load in certain hours above and beyond the SC-3A Option 1 (day-ahead) or Option 2 (TOU) prices.[5] As a result, SC-3A customers have faced hourly prices, complemented (and in some cases supplemented) by inducements from the NYISO that offer additional incentives to curtail load.

Data Sources and Customer Characteristics

Customer market research, designed to gather primary information from customers about their expectations, experiences and actions, was a key component of this study. It consisted of a self-administered customer survey and follow-up telephone interviews with a subset of survey respondents.[6] Additionally, we received basic customer characteristics, customers' hourly billing data and prices over 3-4 years from NMPC.

Of the 130 customers in the study population (representing 149 accounts), 124 were sent surveys in August 2003 and 53 customers, representing 64 accounts, responded. Overall, the survey respondents represent the study population quite well on the basis of usage characteristics and customer supply choices (Table 1). Almost half of SC-3A customers are government/education facilities; industrial customers represent a third of the population and the rest are commercial operations.[7] Industrial customers are slightly over-represented in the sample and government/education customers are under-represented, but these deviations are minor. Survey respondents were nearly twice as likely to enroll in each of the NYISO DR programs as the study population.

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[3] For NMPC, RTP was seen as a default pricing regime consistent with the goals of unbundling electric commodity from transmission and distribution services and creating a vibrant retail market. Demand response concerns did not arise until the first price spikes were seen in NYISO wholesale markets in 1999.

[4] If desired, customers could choose to nominate no load in certain periods. Option 2 customers could purchase their residual energy requirements from a retail energy service provider or at SC-3A rates.

[5] NYISO offers three DR programs: Emergency Demand Response Program (EDRP), Day-Ahead Demand Response Program (DADRP) and Installed Capacity/ Special Case Resource (ICAP/SCR) Program (ICAP/SCR). The programs are described in detail in Goldman et al. (2004).

[6] The interview results are the subject of another paper, Moezzi et al. (2004).

[7] The government/education category includes local, state, and federal government facilities, universities, schools, and other like organizations that share an institutional decision-making structure. Commercial facilities include retail space, office buildings, hospitals, health care facilities, and large, multi-family housing complexes.

Table 1. Characteristics of Survey Respondents vs. Study Population

Characteristic		**Survey Respondents (N=53)**	**Study Population (N=149)**
Business Type	Industrial	40%	30%
	Commercial	21%	22%
	Government/Educational	40%	48/%
Load Characteristics	Average Monthly Peak Demand	4.5 MW	4.9 MW
Basic Supply Choices	Option 2 Nominees	9%	18%
	Competitive Supplier*	50%	53%
DR Program Enrollment	EDRP	38%	21%
	ICAP/SCR	13%	7%
	DADRP	2%	<1%

*at any time since 1998

Customer Survey Results

Customer Acceptance

Survey respondents were asked to rate their satisfaction with the redesigned SC-3A tariff on a scale of 1-5, with "5" indicating highest satisfaction. According to their responses, they are relatively satisfied – the average score was 3.2. This is despite the fact that many customers also indicated that they were unprepared to respond to dynamic prices or make the decision to nominate load on Option 2, and had little or no experience procuring electricity from ESCOs. Additionally, at times, prices were quite high and have increased over the last four years. Nonetheless, only about 15% of survey respondents indicated that they would have preferred a two-part RTP design with a built-in hedge.

Options for Hedging

With RTP as the default service option, SC-3A customers have had several options for managing wholesale market price risk. NMPC's Option 2 tariff provided a hedged (TOU) commodity rate, contracts offered by competitive suppliers could be hedged or indexed in nature, and financial hedges (separate from the purchase of electricity) were also available from retailers. The propensity of RTP customers to purchase hedges may impact their demand responsiveness and is also of interest to policymakers concerned with ensuring that adequate options exist in implementing RTP as a default service tariff.

Option 2 nominations. Based on information from NMPC's customer billing database, 24 customers, or 18% of the target population, made Option 2 nominations. Comparing customers' nominations to their actual usage data, we find that on average customers nominated about 60% of their on-peak usage at the Option 2 fixed price. The other 40% of these customers' on-peak usage was either subject to the day-ahead market price (Option 1) or covered by an alternative supply contract (which, as described below, could have been hedged or indexed). All Option 2 contracts expired in August 2003 and no alternative has been offered by NMPC.

Competitive supply contracts. Table 2 shows the evolution in commodity supply arrangements reported by survey respondents that chose a competitive supplier over three illustrative time periods: winter 1998/99 (the opening of NYISO markets), summer 2001 (shortly after customers first saw day-ahead market prices spike to historically very high levels), and summer 2003 (the most recent period available). The first two rows in Table 2 refer to competitive supply contracts and customers on the default RTP tariff are shown in the third row for comparison.

Table 2. Types of Electric Commodity Supply Arrangements

Type of Supply Arrangement	Winter 1998/99	Summer 2001	Summer 2003
Hedged Contract*	15	12	11
Price Index	2	5	9
NMPC SC-3A (Option 1)	27	27	24
Percent Hedged	*34%*	*27%*	*25%*
Number of customers reporting	*44*	*44*	*44*

*includes flat rate, TOU and volumetric collar arrangements (see Goldman et al. 2004)

All of the hedged contracts reported fully insulate customers against price risk – no portion of the customers' load is subject to hourly-varying prices. It is clear from these results, as well as customer interviews, that use of hedged commodity supply arrangements is declining – from 34% of competitive supply arrangements in 1999 to 25% by 2003. Accordingly, unhedged price indexes (in most cases indexed to SC-3A Option 1) are apparently becoming more common.[8] According to customer interviews, when the retail market initially opened a number of ESCOs offered flat-rate options that were attractively priced. Five years later, such products are reportedly harder to find or include high risk premiums that are unattractive to customers.

Financial hedging options. In addition to taking physical supply from an ESCO, SC-3A customers also had the opportunity to purchase financial hedging products from retailers.[9] All such products reported provide partial protection from price risk without removing the incentive to respond to high prices on the margin.

Based on survey responses, it appears that market activity for financial hedging products is modest but increasing. Of those customers exposed to RTP (either through Option 1 or an indexed supply contract), the proportion taking financial hedges has almost doubled, from 16% in the winter of 1999 to 30% in the summer of 2003. This may reflect the decline in flat-rate ESCO supply offerings and the sunset of NMPC's Option 2 offering.

Role of Enabling Technologies

Customers were asked if they had invested in load-management and energy-efficiency technologies at their facilities prior to and since 1998. About 85% of survey respondents reported making technology investments prior to 1998 (see Figure 1). Energy-efficiency measures dominated these earlier investments; 95% of customers included energy-efficient lighting, HVAC or motors in these upgrades, while 73% included monitoring or control measures. This

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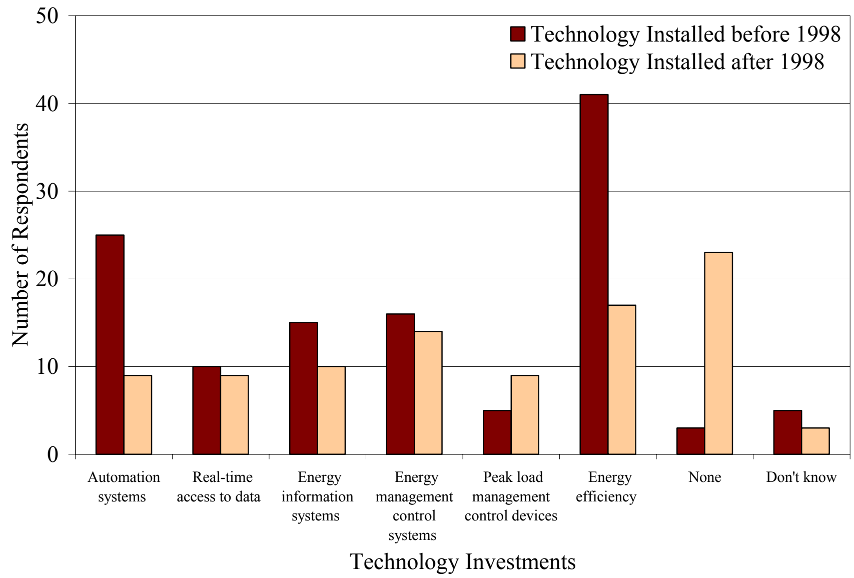
[8] In interviews, many customers reported that the most attractive service offering now available is an index to SC-3A service with a small "shopping credit" – a reimbursement for the utility's avoided customer service costs that was built into the SC-3A rate to encourage development of the retail market.

[9] See Goldman et al. (2004) for details on specific types of financial hedges.

probably reflects customer response to the TOU rates that were in effect prior to 1998 as well as the emphasis of utility demand-side management (DSM) programs on promoting energy-efficiency technologies in the early 1990s.

Figure 1. Investments in Demand-Side Management Technologies



About 45% of respondents reported making technology investments since the introduction of default RTP in 1998. All of them included energy management control systems (EMCS), peak load management controls or energy information systems in their investments – technologies targeted at demand response rather than energy efficiency. [10] Nonetheless, energy efficiency still played a prominent role in these more recent investments; such measures were adopted by 74% of these customers.

The observed shift in emphasis toward DR-enabling technologies may be attributed to three influences: (1) NYISO DR program marketing, (2) customer-initiated strategies to respond to RTP, or (3) New York State Energy Research and Development Agency (NYSERDA) programs that offer incentives for DR-enabling technologies. The NYSERDA programs are intended to enhance demand response state-wide through the adoption of advanced meters, EMCS, peak load management devices and energy-efficiency measures targeted at permanent load reductions. SC-3A customers may have received rebates for purchasing such equipment, or may have received the equipment through a load aggregator. Because these programs were not explicitly targeted to RTP, simply owning the equipment does not necessarily confer that customers actually use it to respond to RTP prices, although it improves the potential for response. Indeed, interviews suggest that many SC-3A customers are not fully aware of the potential applications and demand reduction potential of DR enabling technologies (Moezzi et al. 2004). The correlation between technology adoption and response is addressed further in the next section.

[10] Such technologies, if used to full advantage, can help customers develop automated demand response strategies, reduce transaction costs to implement load curtailments, and minimize service or amenity losses.

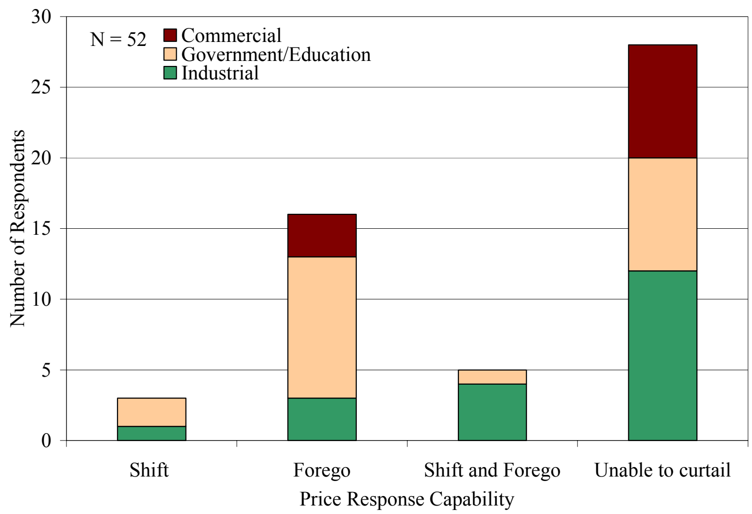
Price Responsiveness

A major focus of this study was to assess the price responsiveness of SC-3A customers. We did this qualitatively through survey questions that probed customers' perceived response capability, and quantitatively through the estimation of price elasticity using demand models.

Customers' Stated Demand Response Capability

We asked survey respondents to characterize their ability to respond to high prices. Over half (54%) claimed they were unable to curtail load; 31% said they could curtail by foregoing electricity usage in certain periods (without making it up at another time), 5% said they could shift load from one time period to another, and 10% said they could both shift and forego usage (Figure 2). Overall, government/education customers were considerably more likely to indicate some type of response capability than other business types (62% vs. 40% for industrial and 30% for commercial customers).

Figure 2. Price Response Capability by Business Sector



Interestingly, almost 30% of the 28 customers that indicated that they were unable to curtail load were enrolled in NYISO DR programs and two-thirds of the enrolled customers have earned curtailment payments during ISO emergency events. Perhaps, some customers may make a distinction: "price response" is adjusting hourly usage to SC-3A prices, while curtailing load during a NYISO program event is a response intended to help keep the electric system secure. The former is considered a business decision undertaken explicitly to avoid high prices, while the latter imparts an intangible but important "public service" benefit in addition to the payment received. Thus customers may respond to incentives to curtail on very short notice (two hours in the case of one NYISO DR program), but may not exhibit the same response, even to a similar price incentive, when it is posted as the day-ahead SC-3A commodity rate. Our empirical price response results (below) support this distinction, at least for some industrial customers.

We also asked the 24 survey respondents that indicated response capability to tell us how they responded (by selecting from a list of possible actions). Table 3 summarizes their responses by the type of response capability and business type. The most common strategies are relatively "low tech", involving reducing usage or shutting off equipment. This is consistent with the finding that most customers can only curtail, not shift, load. Thus, it appears that customers do not always take full advantage of DR-enabling technologies when installed at their facilities (recall that close to half of all respondents had such equipment). Government/education and industrial customers reported a greater number of actions per facility than commercial customers.

Table 3. Actions Taken in Response to High Electricity Prices

Actions Taken by 24 Customers with Response Capability	**N**	**Response Capability**			**Business Type**		
		Shift	Forego	Both	Ind.	Com.	Gov/Edu.
None	3		●		○	○	○
Started onsite/backup generation	1		○				○
Asked employees to reduce usage	17	●	●	●	●	○	●
Turned off or dimmed lights	10		●	●	●	○	●
Reduced/halted air conditioning	15	○	●	○	○	○	●
Reduced/halted refrigeration/water heating	2		○				○
Reduced plug loads (e.g., office equipment)	3	○	○				●
Shut down plants or buildings	3		○	○	○		○
Halted major production processes	2		○	○	○		
Altered major production processes	4	○	○	○	○		○
Shut down equipment	12	○	●	●	●	○	●
Other	7		●	●	○		●

○ action indicated by one or two respondents
● action indicated by three or more respondents

Estimating Price Response

Economists use the term "elasticity" to describe the ability and willingness of a consumer to adjust demand for a good or service in response to price changes. Two kinds of elasticity measure are commonly used. A *demand elasticity* (also known as "own-price" elasticity) refers to the percent reduction of consumption of a good in response to a 1% increase in its price. This measure of elasticity is most often used for consumer goods (e.g., shoes, restaurant meals).

A *substitution elasticity* describes changes in the proportional use of two (or more) inputs to a production process (or delivery of a service) that are potential substitutes in response to a change in the relative prices of the two inputs. In this context, it measures the change in the ratio of peak/off-peak electricity consumption that results from a 1% change in off-peak/peak prices (the "inverse price ratio"). Substitution elasticities are used to describe firm production inputs, in which a given level of output (e.g., production of goods, provision of service) is required and inputs (e.g., electricity) used to produce that output are optimized. For large commercial and industrial electric customers, the substitution elasticity is an appropriate measure of demand response, where electricity is modeled as two substitutable commodities – peak and off-peak power – that are inputs in the production of goods or provision of services. Other case studies of large customer RTP have used this metric (Herriges et al. 1993; Schwarz et al. 2002).

We employ a Constant Elasticity of Substitution (CES) model to estimate SC-3A customers' price response.[11] Customers are assumed to minimize their cost of production or

[11] The CES model was used because it provides a tractable means for estimating substitution elasticities given time, resource, and data availability constraints. However, it does impose certain rigidities on assumed customer behavior,

service provision by determining how much peak and off-peak power to use based on their relative prices, subject to the customer's (perceived or tangible) opportunity costs of switching. For complete details of the model specification, refer to Goldman et al. (2004).

The computed substitution elasticity is a measure of how willing the customer is to substitute given the relative prices of peak and off-peak electricity.[12] A value close to zero indicates very low elasticity – even if peak electricity costs much more than off-peak electricity, the customer is unwilling or unable to switch. Higher, positive values indicate greater ability or willingness to shift production or service provision to off-peak hours.

We defined the peak period as 12 noon – 5pm, and the off-peak period to include all other hours.[13] Elasticities were calculated by regressing customers' daily usage in peak and off-peak periods against the average daily peak and off-peak prices they faced. The analysis uses data for weekdays only during the summers of 2000, 2001 and 2002. We also tested several explanatory variables in the regression equation to quantify the influence of customer-specific and other external factors (such as weather) on price response. Of particular importance, we explicitly accounted for DR program participation. The variables that resulted in the best model fit are presented along with elasticity results below.

Substitution elasticity results. The estimated CES demand model includes the 32 customers for whom extensive firm characteristics and circumstances data were available from the customer survey.[14] Substitution elasticity estimates were derived from the CES demand model for four business categories: government/educational, commercial, industrial, and other.[15]

The average substitution elasticity computed over all business categories and circumstances is a modest 0.14, meaning that a 10% change in the inverse price ratio (off-peak price/peak price) results in a 1.4% change in the ratio of peak/off-peak electricity consumption. However, computing elasticities for each customer group reveals substantial variation, both within and between business categories (Figure 3). Industrial customer elasticities, estimated at 0.11, are comparable to results of other RTP studies (Herriges et al. 1993; Schwarz et al. 2002). Government/education customers are more highly elastic (0.30), which refutes the common perception that industrial customers have the most potential for price response. Commercial customers in the SC-3A class showed very low elasticities overall (0.00).

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most notably that shifting opportunities are limited to the same day's peak and off-peak periods, and that the elasticity of substitution is constant (i.e., the proportional load response is assumed to be the same at high and low prices). The CES model also assumes that customers' output (amount of production or level of service provision) does not vary when customers respond to RTP – only the amount of peak and off-peak electricity used to achieve predetermined output levels is assumed to change. This assumption is addressed with the Load Characterization Model (LRC) below.

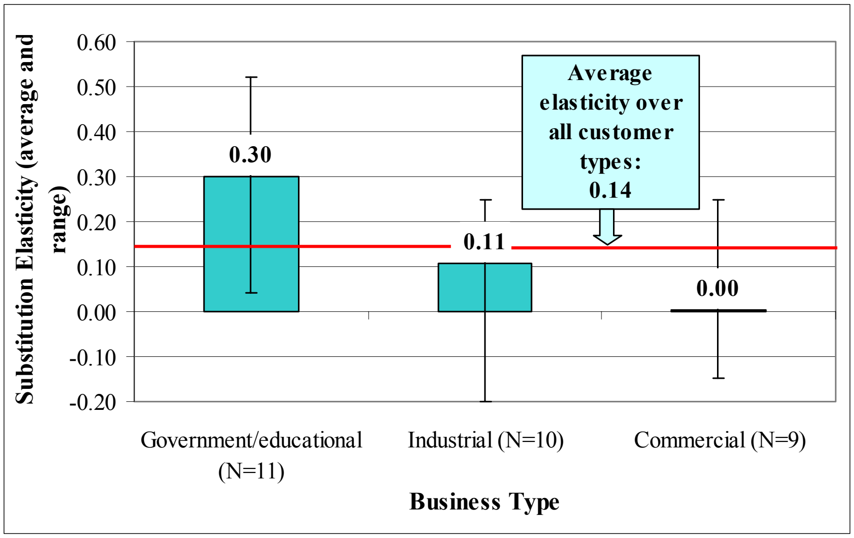
[12] We expect the peak to off-peak usage ratio to decline as peak prices rise relative to off-peak prices. But, as peak prices rise the inverse price ratio declines, so the quantities of both ratios have the same sign and therefore so does the substitution elasticity.

[13] In Goldman et al. (2004) we tested three different definitions of the peak period and found that the longer the peak, the lower the estimated elasticities. The longest peak period, reported here, resulted in the best model fit.

[14] Only those customers that answered all relevant survey questions for each explanatory variable could be analyzed. The model parameters were generally of the expected sign and significance level. The observed R-square of 0.25 is relatively high compared to that reported for electricity demand models estimated under similar circumstances (Schwarz et al. 2002).

[15] Customers in the "other" category had unique identity and circumstances that required masking. Moreover, their elasticity estimates are generally insignificant and of the wrong sign, implying that their usage behavior is not well defined by the model specification.

Figure 3. Substitution Elasticities for 32 SC-3A Customers by Business Type



We also estimated substitution elasticities in an unbundled manner to isolate the influence of various factors on customer response (Figure 4). The first table in Figure 4 shows "base" elasticities for cohorts of SC-3A customers defined by business type and EDRP participation, without adjustment for any other factors. For EDRP participants, we computed separate elasticities for EDRP event and non-event days.[16] We find that under most circumstances government/educational customers are significantly more price responsive than other customer groups – this reinforces the overall finding reported above. However, the impact of EDRP participation on customer response differs among customer groups. For government/education customers, EDRP participation seems to reduce elasticity. EDRP participants on non-event days are 20% less price elastic than customers of the same business class who are not in the program at all. On event days, their response is lower still (15% less than for participants on non-event days). Commercial customers show these same trends. One possible explanation for this apparently paradoxical result is that these customers have already responded to SC-3A day-ahead prices when the same-day EDRP event is called, leaving limited opportunity for additional load shedding. Note that for government/educational customers, elasticities even on response days are still positive – thus they do respond, but to a reduced degree. Because the CES demand model assumes elasticity is constant at all prices, customers that display such a response threshold will show relatively low elasticities at high prices. Further research using models that do not impose the constraint of constant elasticity may resolve this apparent paradox.

Industrial customers enrolled in EDRP, on the other hand, show dramatically increased response during EDRP events (0.40 on event days vs. 0.03 on non-event days). For these customers, the EDRP program appears to entice price response that SC-3A prices do not.

The second set of results in Figure 4 shows the impact of additional factors on SC-3A customers' responsiveness, and are additive to the base elasticities in the first table. These results suggest that participation in other NYISO DR programs (DADRP and ICAP/SCR) enhances

[16] During the study period, there were five days when the NYISO activated the EDRP program. On such days, during event hours, EDRP participants were assumed to face the $0.50/kWh curtailment incentive paid by the program as their SC-3A "price".

price response (the base elasticity estimates are increased by 0.33 and 0.16 respectively). This is not surprising – both programs provide financial incentives to curtail and assess penalties for non-compliance. This suggests that the prospect of getting paid to curtail boosts customer response over that which would be forthcoming from RTP alone.[17]

Figure 4. Impact of Characteristics and Circumstances on SC-3A Customers' Substitution Elasticities

Base Substitution Elasticity Estimates

Average Values for Customer Groups		EDRP Participation?		
		No	Yes	
			Event Day?	
			No	Yes
Business Type	Gov/Edu	0.5	0.40	0.34
	Commercial	0.26	0.18	0.06
	Industrial	0.24	0.03	0.40
	Other	-0.02	-0.21	0.22

Additive Impact of Other Influences

Additional Circumstances	If "yes", increment base elasticity by…
Customer factors	
Is the customer a participant in…	
...DADRP?	adding 0.33
...ICAP/SCR?	adding 0.16
Is the customer's peak usage between 12 noon and 5pm?	subtracting 0.19
Does electricity account for >10% of operating costs?	subtracting 0.08
Did the customer install DR-enabling technologies…	
...before 1998?	subtracting 0.11
...after 1998?	subtracting 0.04
Other influences	
Is the daily peak temperature higher than 70 degrees?	adding 0.02
Is the year 2001?	no effect

The next two results are fairly intuitive. Customers that report peak usage between noon and 5pm and those with high electricity intensity are less responsive than other customers, all else equal. This is consistent with the notion that it is harder for customers to curtail when critical business activity and electric use coincide with times of high prices.

The technology investment results, however, are counter-intuitive; investing in "enabling" technologies appears to *decrease* responsiveness. This effect is much more pronounced for the DSM-type investments made before 1998. For investments made after 1998, the negative impact on elasticity is small, but we would expect these DR-oriented investments to actually assist response. As noted already, it may be that customers have received equipment through NYSERDA programs but have not taken full advantage of its capabilities. Another possibility is that the equipment was installed relatively recently (we asked about investments *at any time* since 1998) so that it was not available during the years covered by our model. Finally, technology investment may be correlated with other factors that reduce price response but are not accounted for in the model. Further research is needed to more clearly specify the impact of technology on price response.

[17] Note, however, that all DADRP and ICAP/SCR participants in our sample are industrial customers, so we cannot know for certain that government/educational or commercial customers would respond in the same way.

Load Response Characterization (LRC) Model

The CES model described above assumes that customer RTP response consists of shifting usage – power curtailed during peak periods is assumed to be balanced by equivalent increases in usage in the same day's off-peak period. However, many customers reported curtailing or foregoing discretionary usage during high-priced periods without making it up later (see Figure 2). In cases where customers simply forego discretionary usage, the estimated elasticity of substitution underestimates the nominal level of the reduction in peak usage.

To address this issue, we employed a Load Response Characterization (LRC) Model, following the model posed by Patrick (1990), which distinguishes load shifting from foregoing consumption (see Goldman et al. 2004 for the full specification). The LRC model specifies an empirical relationship between the total daily load change and the change in peak load. A "conservation" behavior parameter is estimated from customer's hourly electricity usage data to express the degree of foregone consumption relative to a customer baseline (CBL). This parameter ranges in value from zero (complete shifting) to one (complete "conservation"), or greater. Values between these extremes indicate combinations of shifting and discretionary peak reductions.

When combined with elasticity of substitution results, the conservation parameter separates out behaviors that are not fully characterized by the substitution elasticity and allows a more complete picture of aggregate load response than substitution elasticities alone can provide.

Load shifting vs. "conservation" curtailment behavior. Table 4 displays the estimated "conservation" parameters for SC-3A customers by business category. Average sector-specific values range from 0.85 (industrial) to 0.91 (commercial), confirming survey results that indicate customers primarily curtail discretionary usage rather than shift load. The estimate ranges in Table 4 bound the results within each business classification.[18]

Table 4. "Conservation" Parameter Estimates by Business Classification

Business Type	Number of Customers	Estimate Range	Average Conservation Coefficient
Industrial	10	0.50 – 0.92	0.82
Commercial	9	0.64 – 1.00	0.91
Government/educational	11	0.64 – 1.09	0.85
Other	*	0.80 – 0.98	0.89

*Includes fewer than 5 customers

Aggregate Demand Response Potential of SC-3A Customers

The CES and LRC estimates may be used together to predict the level of demand response that can be expected from high-price events. Combining elasticity of substitution estimates with customers' computed "conservation" behavior parameters provides a comprehensive estimate of the aggregate response of SC-3A customers, taking both factors into account.

[18] Parameter estimates greater than 1.0 indicate the customer actually reduces load by a greater proportion in the off-peak period than is curtailed (foregone) in the peak period.

To estimate the peak-period response of SC-3A customers as a group, the elasticities estimated for the four business sectors were extrapolated to the population of SC-3A customer accounts, using sector load weights.[19] Figure 5 illustrates the resulting peak period curtailment curves, first using the substitution elasticities alone (shifting behavior), and then adjusting to account for the estimated "conservation" effect. At a reference price of $0.50/kWh, the difference is almost 30 MW of additional demand response due to curtailments.

Figure 5. Aggregate SC-3A Peak Period DR: Shifting Only and Conservation Adjusted

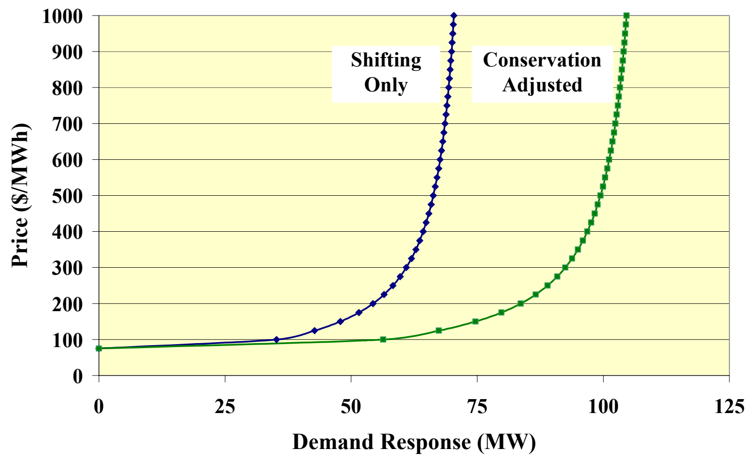
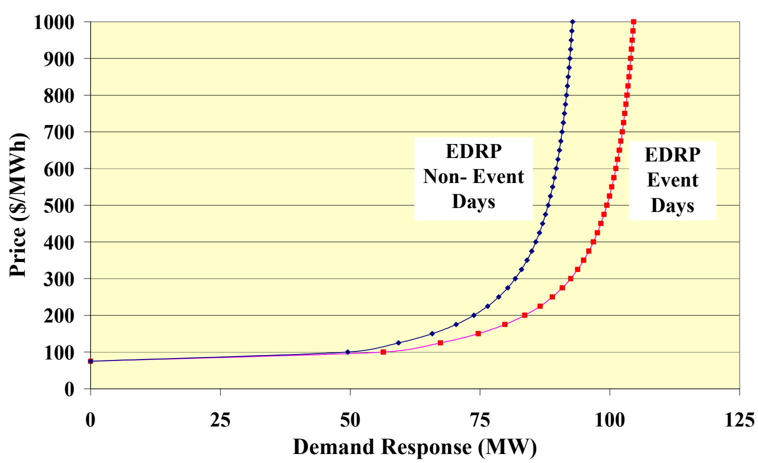


Figure 6 illustrates the interrelationship between the SC-3A tariff rate and EDRP. The declaration of an EDRP event day by the NYISO adds an additional 12-15 MW to the estimated curtailments by SC-3A customers. In both cases, over 90% of the curtailment potential is achieved at a price of $0.50/kWh, and the maximum curtailment amounts to about 18% of the coincident peak load of the SC-3A customer class.

Figure 6. Estimated Impact of EDRP Events on SC-3A Customers' Peak Period DR



[19] The elasticities were estimated using 32 customers. There were 141 SC-3A accounts available for the aggregate demand response estimate.

Conclusions

This case study of large customer RTP experience at NMPC reveals several qualitative results of interest to policymakers considering RTP implementation. First, despite seeing somewhat volatile and steadily rising electricity costs, SC-3A customers are largely satisfied with the tariff. However, the context in which this tariff was adopted – coordinated with the creation of wholesale markets and the introduction of retail market competition, as well as declining price volatility in recent years – probably influences this result significantly. Subjecting customers to default RTP without ensuring the availability of diverse and fairly priced alternatives would likely be a harder sell.

Second, many SC-3A customers indicate through their actions and statements that they would prefer to hedge – either through flat-rate supply contracts or financial hedges – but that if the cost of a hedge is too high they will remain on RTP. As of 2003, 50-55% of SC-3A customers were exposed to market price volatility, either through the default tariff or indexed supply contracts. The experience in New York has shown that retailers may not offer adequate hedging options, so policymakers implementing RTP should ensure that such opportunities exist so that customers can choose the level of risk exposure they are comfortable with.

Third, DR-enabling technology adoption among SC-3A customers is modest – 45% of customers have made investments since RTP was implemented. For those that have made investments, qualitative and quantitative evidence suggests that it does relatively little to assist in responding to RTP prices. Thus there is a strong need for customer education and assistance to develop response strategies to realize inherent price response potential.

Fourth, our empirical analysis of SC-3A customers' price response reveals that although over 54% of survey respondents said they couldn't respond to prices at all, many can and do participate in emergency DR programs. Government/education customers exhibit particularly high elasticities at all times, while industrial customers have lower response to day-ahead prices but are clearly motivated by ISO DR program inducements. This suggests that pay-for-performance DR programs complement RTP, producing additional DR when it is most needed.

In summary, the NMPC experience shows that default RTP for large customers does deliver modest demand response, even when some customers seek to hedge against price volatility. Better dissemination of enabling technologies and customer education regarding response strategies would probably improve DR beyond that observed for SC-3A customers, yet to achieve socially optimal levels of DR at critical times, RTP is best implemented as part of a portfolio of DR options.

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