Price Response and Demand Response Program Portfolio

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1. Introduction

KCP&L retained the team of KEMA Services Inc. and UtiliPoint International (KEMA Team) to develop a robust portfolio of demand and price response programs directed to all customer classes. There are a number of factors that are encouraging KCP&L to initiate this effort. These factors span such needs as KCP&L's capacity requirements for their service territory over the next several years, regulatory initiatives and the potential to improve customer satisfaction by offering rate payers more options to management their electrical costs.

A robust portfolio of demand and price response programs offers a number benefits to the utility and its customers:

- Participant savings for those customers who actively manage their electric use.
- Increased off-system sales from freed up native generation capacity.
- Reduced price volatility and increased system security.
- Deferred and avoided capacity costs.
- Improved net social welfare from more efficient resource utilization.

KCP&L currently has a number of demand and price response programs in its portfolio. These are shown in Figure 1-1:

Figure 1- 1 KCP&L's Current Portfolio

Program	Residential	Small C&I	Medium C&I	Large C&I
Pricing Programs				
Time of Day	√			
Real Time Pricing			√	√
Capacity Programs				
Voluntary Load Curtailment			√	√
Peak Load Curtailment Credit (KS only)			√	√
MPower (C&I Curtailment – MO only)			√	√
Direct Load Control (Optimizer)	√	√		

With the notable exception of the Optimizer program, few of KCP&L's customers are currently participating in these programs. We understand that KCP&L is seeking to broaden participation as its system load is growing and they are seeking to offset the need for new combustion turbines through load responsive behavior from their customers as well as energy efficiency. The scope of this study focuses on these needs.

Our approach to developing a portfolio of programs to foster demand and price response was guided by four main principles:

- Sustainability – employ programs are compatible with, or can adapt easily to, current and foreseeable market designs. In particular they must be amenable to how SPP utilizes and values capacity provided by demand and price response programs,

- Predictability – Both KCP&L and SPP schedulers and dispatchers must be able to reasonable forecast the load changes undertaken by program participants in order to fully and effectively incorporate demand diversity into system operations,
- Cost-effective – the programs should deliver quantifiable value that exceeds the costs of implementation,
- Proven – utilize designs that have delivered consistent and predictable results in other markets, and adapt them to KCPL's market circumstances

The KEMA team made extensive use of KCP&L supplied customer and supply data allowing us to model KCP&L's market supply and demand characteristics to determine the benefits of price and demand response. In characterizing capacity conditions, the KEMA team reviewed SPP forecasts of capacity costs, available capacity resources defined by KCPL and the avoided costs that KCP&L developed to reflect the cost of a combustion turbine ("peaker") unit. We looked at customer data as represented by billing class and KCP&L's appliance saturation survey as well as third party sources such as FERC and Census data. The report also draws extensively on the experiences of other markets as gained through the team's direct experience and extensive research.

In reviewing portfolio options we sought to create a portfolio derived from proven platforms that are compatible with, or can adapt easily to, current and foreseeable market designs. The end result is that in several instances, the proposed portfolio utilizes platforms KCP&L has already adopted confirming that KCP&L already has a portfolio that in addresses the issues described above. That being said, the proposed pricing and capacity plans themselves in all cases involve changes in design. In some cases, for example the Optimizer program, these are relatively modest and in others, such as MPOWER and VLR, the KEMA team has proposed substantial design modifications to achieve the goals of sustainability, predictability, and cost-effectiveness. The expansion of pricing programs into new segments effectively and purposefully alters the overall nature of KCP&L's current portfolio. These are summarized in the following subsection (1.1) and more fully discussed in sections 4 through 7 of this document.

1.1 Proposed Portfolio

The proposed portfolio defines two classes of offerings a) Pricing Programs that utilize streaming pricing signals or time-differentiated price schedules to convey to customers the contemporaneous cost of supply and b) Capacity Programs that provide incentives for demand reductions under specified circumstances, and in the case of MPOWER, penalizes the customer if they are not provided. Pricing programs are devised to achieve efficient resource utilization to maximize customer and social welfare. Capacity program recognize the fact that prices can not always convey actual supply circumstances, and as a result at times system dispatchers need to utilize load reductions to preserve system security. The individual pricing plan and capacity programs of each category and the KCP&L customer segments, to which they are to be offered, are listed in Figure 1-2 below:

Figure 1-2. Proposed Program Portfolio and Customer Classes

Program/Class	Residential	Small GS	Medium GS	Large GS	Large Power
Pricing Programs					
RTP	√	√	√	√	√
VPP	√	√	√	√	√
TOU	√	√	√	√	√
Reliability/Capacity Programs					
DLC Plus	√	√			
VLR Plus			√	√	√
MPOWER Plus			√	√	√

Although these pricing and capacity programs have similarities to KCP&L's current offerings, our proposed designs render the programs more robust and more attractive to the target customer segments. Figure 1-3 provides a feature-by-feature comparison of KCP&L's existing pricing programs with those we propose and Figure 1-4 provides that comparison for the demand curtailment programs.

Key aspects of the portfolio include:

- Program participation is voluntary. KCP&L will maintainers current rate structure for the immediate future as the default rate, which constitutes the most fully hedged, and therefore the most expensive service option in the portfolio.

- All customers will have the option to choose to participate in a pricing program, and a capacity program. For example, residential and small commercial customers can elect to stay on the traditional rate, or elect TOU, VPP or RTP, on an annual contract basis, and then if they so choose, they can participate in DCL Plus, which involves allowing KCP&L to curtail their AC. Commercial and industrial customer have the same choices in pricing plans, adapted to their class characteristics, and can choose between VLR Plus and MPOWER Plus. .

- TOU pricing plans are intended to induce sustained changes in usage behavior, either through lifestyle or business activity adjustments or through enabling technology like appliance or equipment control equipment. These plans appeal to customers that place a high value on certainty and utilize established routines.

- The VPP and RTP programs link daily and hourly energy prices to contemporaneous market conditions to induce reductions in usage either through rescheduling activities of reducing discretionary electricity usage. Because RTP involves a high degree of involvement, the participation level for residential and small business customers is likely to be modest, at least initially. The VPP pricing option provides a simpler dynamic rate option for these customers that achieves provides nearly the same benefit opportunities under many circumstances.

- We propose to open the DLC program to small business customers and to provide incentives for these customers to install direct control technologies beyond the controllable thermostats. Allowing customers to choose both VPP and DLC may result in increase interest in the DLC option, especially if the customer can specify a price point where the load control strategy would be deployed.

- Capacity program will be used by system dispatchers to resolve reliability and security circumstances. Unlike the current programs, curtailment will not be used as part of commercial transactions. The pricing programs convey economic conditions. Capacity program provide dispatchable resources under circumstances where prices do not convey the actual value of curtailments

- Our analysis of the current MPOWER and VLR programs from the customer perspective suggests that most customers would view the VLR program as being more attractive in terms of the expected payment. Our assessment of avoided costs suggests that the MPOWER event based incentives should be increased. Increasing the MPOWER event-based incentives will tend to make MPOWER the preferred option for many customers given its upfront incentive payment.

- Other proposed changes to MPOWER include:
  - Simplifying the offer by limiting it to just a one-year contract. Few customers are likely to have interest for a multiple-year commitment. Moreover, capacity additions in the near future suggest that value of MPOWER will drop off substantially in 2010. KCP&L may elect to offer multi-year contracts at levelized incentive rates with additional benefits that reflect the transactions costs of marketing the program yearly. However, such offer must include buy-out provisions tied to contemporaneous replacement capacity costs.
  - Reducing the minimum customer pledged load reduction to 50kW for both MPOWER and VLR increases the eligible population of participants. We also propose that KCP&L examine the benefits and costs of allowing third party aggregators to bundle smaller customer together to achieve the required load reductions level, and thereby participate in both MPOWER and VLR.
  - We recommend that the capacity program performance be measured using a Customer Baseline Load that uses recent usage history to define what the customer's load would have been and it not reduced load during a capacity program event rather than a designated firm power level.

- Consideration of a DR control technology incentive to encourage customers that have signed up for any of the programs to install control technologies that make it possible for the customer to provide a greater load reduction in response to prices and a capacity program.

Figure 1-3 Comparison of Existing and Proposed Pricing Programs

KCPL Price Response Programs - Comparison of Proposed Portfolio Plans with Exising Traiffs							
Feature	**Existing RTP**	**Proposed RTP**	**Existing VPP**	**Proposed VPP**	**Existing TOU**	**Proposed TOU**
Eligibility	C & I (Medium GS >500 KW through Large Power Svc)	**All Customers**	***No existing VPP rate***	**All Customers**	All Customers	**All Customers**
Metering	Hourly interval meter	Hourly interval meter		**Hourly interval reads using exisiting meters**	TOU meter	**TOU meter**
Price Postings	Day Ahead by 4:00 p.m.	Day Ahead by 4:00 pm		**Peak: Day Ahead by 4:00 p.m. Off-Peak: Annually TOU Schedule posted each February**	No rate revision since August, 1999	**Annually - TOU prices posted each February for the following April - March**
Price Formation	Algorithm employs synthesized marginal energy, marginal outage, and effective energy	**SPP market-based**		**Off-peak price determined by annual marginal cost forecast. Peak price is SPP market-based**	Determined by traditional rate development	**Determined by annual marginal cost forecast**
Peak Season	N/A	N/A		**June 1 - September 30**	Varies between May 16 - September 15 and June 1 - September 30	**June 1 - September 30**
Peak Period Hours	N/A	N/A		**2:00 - 6:00 p.m. weekdays**	1:00 - 7:00 p.m. weekdays	**2:00 pm - 6:00 pm weekdays**
Off Peak Period Definition	N/A	N/A		All other times	All Other Times	All other times
CBL	"Blocked"(averaged) CBL by daily TOU period and season	**Blocking of hours only if customer and KCPL agree, otherwise hourly**		N/A	N/A	N/A

Figure 1-4 Comparison of Capacity Programs

KCPL Capacity Programs - Comparison of Proposed Portfolio Plans with Existing Tariffs						
	Existing MPOWER	Proposed MPOWER *Plus*	Existing VLR	Proposed VLR *Plus*	Existing Optimizer	Proposed Optimizer
Eligibility	C & I	Same as Existing MPower	C & I MPOWER Rider customers may also participate in events	***All C & I***	Small C & I Residential	Same as Existing Optimizer
Contract Term	One, Three or Five Years	***One Year***	One Year	Same as Existing VLR	Three Years	Same as Existing Optimizer
Metering	Hourly interval meter	Same as Existing MPower	Hourly interval meter	Same as Existing VLR	DLC equipment provided by KCPL	Same as Existing Optimizer
Peak Demand	N/A	N/A	100 kW	***100 KW (aggregation permitted)***	N/A	N/A
Minimum Curtailable Demand	200 KW Must be the same amount for each month of the contract	***100 KW***	None	***100 KW (aggregation permitted)***	None	Same as Existing Optimizer
Event Periods:	Mandatory: Noon - 10 PM Monday through Friday	***Mandatory: All hours***	Voluntary: All Hours	Same as Existing VLR	Mandatory: Summer Weekdays	***Mandatory: All Hours***
Event Season:	May-September for 1 yr or 3 yr contracts Annual for 5-year contracts	***Annual***	May - September	***Annual***	Summer Season	***Annual***
Event Advisory:	None	***Day-ahead as a courtesy only***	None	***Day-ahead as a courtesy only***	None	***Day-ahead as a courtesy only***
Event Notice:	4 hours prior to beginning of the event (1yr contract) 2 hours prior to beginning of the event (3 yr contract) 1 hour prior to beginning of the event (5 yr contract)	***2 hours prior to beginning of the event***	Not all customers are notified of each event Offer price for curtailed load sent to customers must provide written notice within 2 hours of notice	***2 hours prior to beginning of the event AND Customer must opt in with estimated reduction amount prior to event start in order to qualify for event payment***	None	Same as Existing Optimizer
Event Duration:	Minimum of 2 hours Maximum of 8 hours	***Minimum of 4 hours***	Not specified in tariff	***Minimum of 4 hours***	Maximum of 4 hours	Same as Existing Optimizer
Event Frequency:	Limited to once per day No more than 3 consecutive days per week	***Limited to once per day***	Not specified in tariff	***Limited to once per day***	Limited to once per day	Same as Existing Optimizer
Event Limits:	up to 25 events per year (1 yr or 3 yr contract) up to 30 events per year (5 yr contract) Not to exceed 120 hours per calendar year	***None***	Not specified in tariff	***Limited to once per day***	Limited to once per day	Same as Existing Optimizer
Capacity payment:	Customer may receive a one-time compensation to purchase equipment to participate Program Participation Payment of $16 per KW of Curtailable Load (1 yr contract) Additional payments may be made for 3 yr or 5 yr contracts	***Established annually based on the value of resource adequacy capacity reserves***	Not specified in tariff	None	None - Equipment provided by KCPL	Same as Existing Optimizer
Event energy curtailment payments:	$0.36 per KW of Curtailable Load for each event	***$0.50 per kWh of verified performance***	Variable: price quoted at time of event	***$0.50 per kWh of verified performance***	None	Same as Existing Optimizer
CBL:	Estimated Peak Demand Summer only (1 yr or 3 yr contract) Summer and Non-Summer (5 yr contract) Firm Power Level of at least 200 KW less than Estimated Peak Demand	***Dynamic hourly value incorporates most recent historical load, with an adjustment for current weather conditions***	Average Monthly Peak Demand based on Max KW for June, July, August, and September	***Dynamic hourly value incorporates most recent historical load, with an adjustment for current weather conditions***	N/A	N/A
Event performance kWh:	The difference between the Estimated Peak Demand and the Firm Power Level	***The difference between actual load during the event and the CBL by hour***	(Average Monthly Peak Demand * .90) - Actual hourly load during event	***The difference between actual load during the event and the CBL by hour***	N/A	N/A
Buy-through:	If event is called for economic reasons, customer may buy-through at a price determined at the beginning of the event No buy-through for Operational Curtailment event	***None***	Not specified in tariff	None	Limited to 1 per month	Same as Existing Optimizer
Non-performance penalty:	$1.25 per kWh over the Firm Power Level in each hour where average hourly load exceeds the Firm Power Level Waiver of non-compliance for one event per season at KCPL's discretion (Customer must request the waiver) Non-compliance for 3 events in a calend	***150% of Capacity payment on difference between contracted kW and highest previous 12 months event kW curtailed*** ***Derating: average event performance over previous 12 months used to calculate subsequent year's maximum contracted capacity obligation***	None	None	Option to withdraw from program at no cost to customer Contract may be terminated on 90 days written notice	Same as Existing Optimizer

In addition, to the programs offered the team considered and chose not to include two offerings: Critical Peak Pricing (CPP) and electronic bidding. Our reasons for not proposing them are described in Section 4.3. The key reasons can be summarized as follows:

- Critical Peak Pricing (CPP) is not included because VPP and RTP are more effective in conveying contemporaneous prices, thereby achieving efficiency resource utilization, and MPOWER and VLR Plus are more effective in achieving load reductions needed to preserve system security.
- Electronic bidding was not included because RTP and VPP provide comparable or better benefits to customers and to KCP&L, in part because the lack of transparent spot market prices. As SPP matures and price discovery becomes easier, opportunities may arise for bidding load as a resources into SPP's day-ahead market

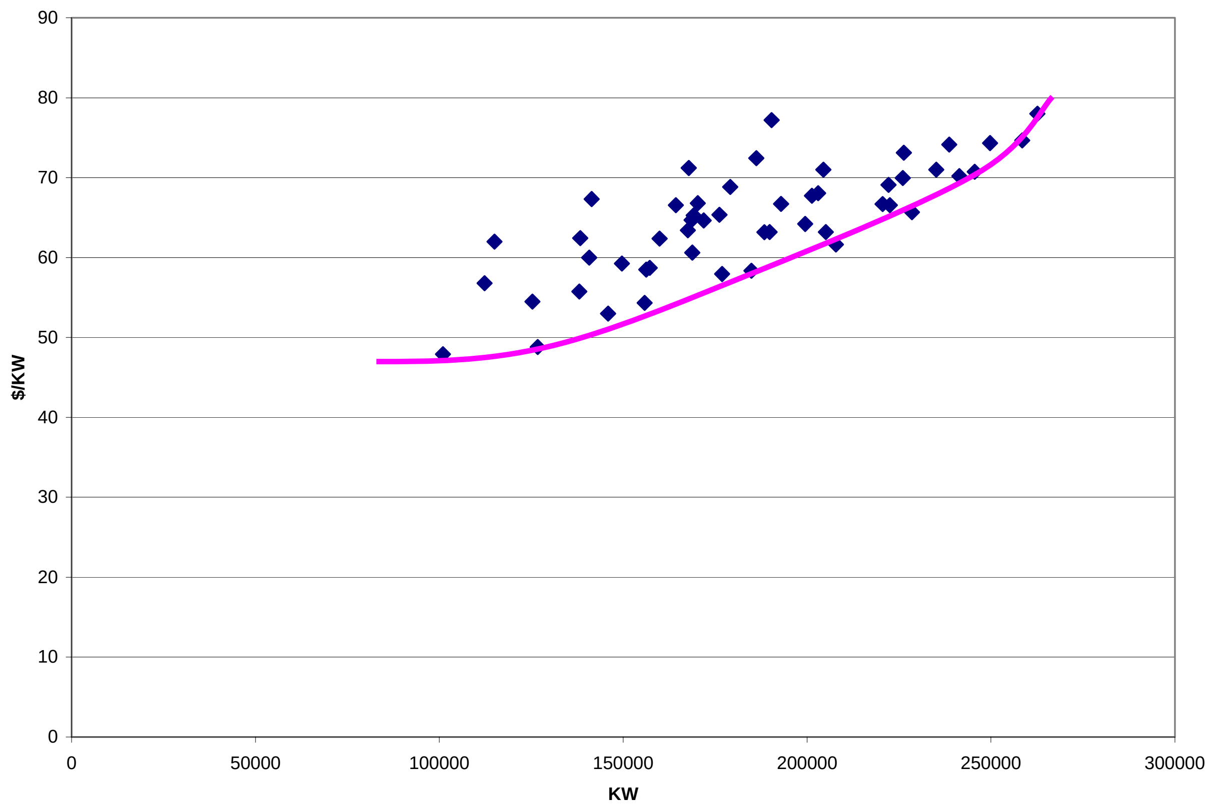
Figure 1-5 summarizes our mid-case estimates, which can be interpreted as representing expected supply conditions, of the peak load reduction contributions for pricing and capacity programs. This figure represents the contribution of demand and price response programs as necessary to meet loads within KCP&L's required reserve margin.

Figure 1-5. Expected Contribution by Portfolio Program Type 2007-2010

	2007	2008	2009	2010	2011
KCP&L Capacity Req. (MW)	49.3	66.6	91.9	0	0
Pricing Program Contributions	2.5	3.2	10.3	13.4	20.9
DR Response Contributions	46.8	63.4	81.6	0	0

KCP&L also asked for estimated impacts would be for differing levels of expenditures. Figure 1-6 shows the results of 60 separate simulations for various combinations of marketing expenditures and incentives for the demand response programs. For each simulation we tested various combinations of marketing budgets and program allocations to derive the total cost of the portfolio. The X axis shows the overall impact and Y axis shows the total cost estimated to reach the demand reduction level. These simulations highlight the two major fundamentals that 1) incentives need to be a level that will move customers to actions and 2) there must be a sufficient level of marketing, sales and customer education for a program to be successful.

Figure 1-6 : Summary Impact Simulations



All that being said, it is important to note, that there is considerable uncertainty as to the results that may be achieved. Each of the offerings will require customer recruitment and acceptance, and continuing marketing and sales efforts. These efforts will need to be tailored to the appropriate segments with messages that are understandable to each segment. In other words, success is not simply a function of expenditures. Enterprises with similar budgets often have differing results because of the variation in quality of the marketing and product packaging efforts. For example, Gillette and Schlick may both have similar product lines and advertising budgets, but one firm has a message that resonates more with the public and gains a larger market share.

It will take several years for the pricing programs to achieve a significant market penetration. For the short term, the capacity programs will need to provide the bulk of the load reduction impacts through 2009. It is expected that approximately half of the expected load reduction will come from DLC while the other half will come primarily from MPOWER. It is anticipated that many current VLR customers may switch to MPOWER; but, VLR will continue to be the preferred option for those larger customers that are unable to make a firm commitment for load reduction.

As stated above, effective marketing will be the key determinant of whether the above program goals will be met. For residential and the small business segments, on-going direct mail, email, and telemarketing campaigns will be the most effective way to sell DLC, TOU, RTP and VPP.. In addition, these options should be offered as part of any customer service interaction such as a new service request, on-line bill payment, or a high bill inquiry. The key marketing message is that KCP&L is providing the customers with options for reducing their electric bill. A rate assessment tool will likely be required in order to sell the customer on the TOU, RTP or VPP option. These may be incorporated into KCP&L's Energy Analyzer web site. Our experience has shown that customers are only willing to switch to a new rate option if it can be shown that they are likely to benefit without significant change in the appliance usage patterns.[1] Therefore, the availability of tools such as the enhanced Energy Analyzer will be critical in making the sale.

[1] In 2003 KEMA was retained by the California Energy Commission and investor owned utilities to market the CPP rate to residential customers throughout California.

The most successful marketing approach for larger business customers is one-to-one sales via program staff or account representatives. These customers will require an economic assessment of the various options and may also require assistance in identifying load reduction strategies. The offering of the technology incentives may be viewed as a deal sweetener but the expected bill reduction from participation will be the primary determinant on whether the customer chooses one of the various programs.

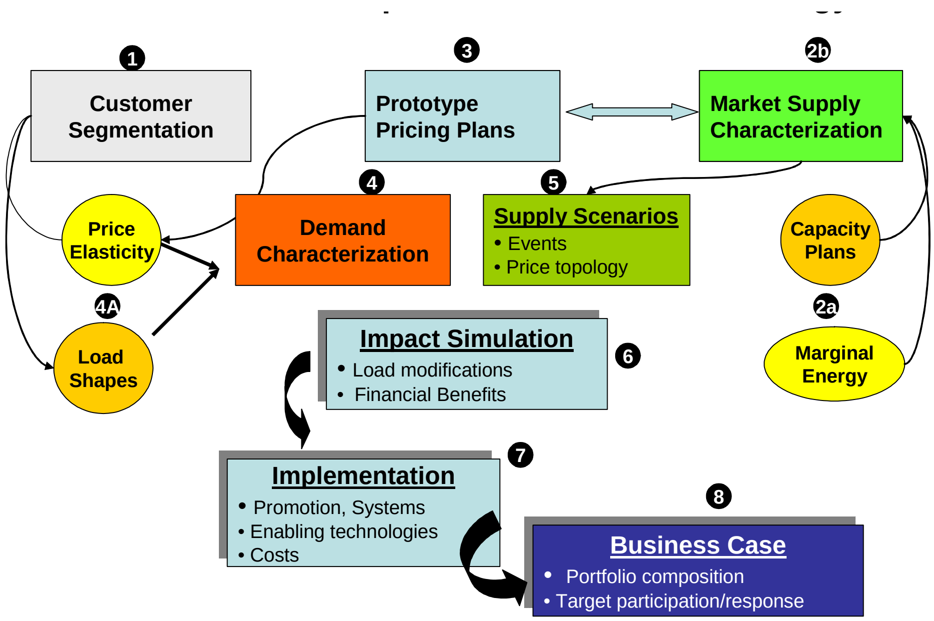
In conclusion, KCP&L should commit to creating a robust portfolio of price and demand response programs. This will benefit KCP&L by reducing price volatility and providing cost-effective capacity; these programs benefit KCP&L's customers by providing more options to manage their electric costs and provide all stakeholders with a far more economically efficient utility.

1.2 General Approach

In developing the portfolio for KCP&L, the KEMA estimated the benefits expected from price and demand response programs recommended to guide program implementation. The analysis utilized the PriceFX model developed by UtiliPoint International to quantify price response and to establish the level and distribution of benefits associated with price and demand response.

Figure 1-7 illustrates this process. Detail about the UtiliPoint's PriceFX model is provided in chapter 9 of this document. This approach integrates our collective understanding of how customers respond to prices and program features with impacts of load changes on customer and market circumstances that characterize KCP&L's market.

Figure 1-7. PriceFX Demand Response Valuation Methodology



The benefits estimation process, and how it leads to a business case for the proposed portfolio of demand response programs, is as follows:

1. Customer segmentation. As described in Section 2 - Characterization of Demand, the KCP&L customer base was sorted into segments that share characteristics or circumstances that are likely to result in a common price response capability. This categorization enables the assignment of price elasticities to estimate price response, and provides a focus for developing program promotional plans, and investigating the impacts of enabling technologies.

2. Market supply conditions. As described in Section 3 – Characterization of Supply - we studied several sources of pricing data from KCP&L in order to estimate where system prices will go over the next five years. Since the Southwest Power Pool (SPP) is only now defined and created there is a degree of uncertainty as to its direction concerning a

formal capacity market. Currently, there currently is none, nor is one foreseen, at least not in the formal structure of the Northeast ISOs. Finally, SPP does not currently operate any demand response programs, and it has not indicated when and if it would do so. Therefore our team utilized KCP&L's capacity expansion plans to establish the value of avoided capacity to define the benefits associated with load reductions coincident with the system peak. Finally, we gathered data from KCP&L's dispatchers and planners to determine the value of load reductions undertaken to protect system security, utilizing methods developed by UtiliPoint and used by several ISOs for the same purpose.

3. Prototype pricing plans. In Section 4- Proposed Portfolio of Programs - we propose a portfolio price and demand response programs. This portfolio was based on our discussions with KCP&L, and an assessment of market supply conditions. These programs can broadly be classified into a) pricing rationing or efficiency programs and b) quantity rationing or reliability programs. Programs in the first category include real-time pricing (RTP), variable peak pricing (VPP) and time-of-use (TOU) pricing. Programs in the second category include a direct load control program (Optimizer) and two curtailment programs (MPOWER Plus and VPP plus).

   A key point pertaining to pricing programs is that these programs will provide benefits to KCP&L without support from SPP. We anticipate that support from SPP will ultimately be required for the reliability programs to obtain their full value and to be part of a long term sustainable effort.

   Our analyzes included the following:

   a. Demand characterization. Customer segments were assigned price elasticities utilizing the collective experience gleaned from pilots and programs implemented around the country. A key input was the recent DOE study of the value of demand response. It provides a summary of what 30 years of analyses, including the most recent California pilot.[2]

b. Supply scenarios. Load changes are undertaken because system conditions warrant asking for them (induced demand response) or the prices customers pay cause them to change their usage pattern (autonomous price response). In order to estimate participant benefits and the benefits that inure to other customers and society, market conditions for future years were analyzed. These results were used to estimate the number of events likely to be called (induced demand response) and the frequency of high prices would occur. These were then used to estimate program response. Scenarios were developed for three supply conditions: low, normal, and high. The scenarios were chosen based on the volatility of results as indicated by KCP&L's MIDAS simulations.

4. Impact simulations. In Section 5 – Simulated Impacts–Price Response, we provide simulations involving how customers adjust load to the supply conditions of each scenario under each or the pricing programs. In Section 6 – Supply of Regulatory Capacity we describe the impacts of programs that require that customer curtail or be penalized.

5. Implementation. In Section 7 Implementation Plans, describe promotional plans to ensure that they are targeted to the right customers and that those customers are fully informed about the opportunity they offer.

In summary, we developed benefits from the bottom up, as they would actually be realized in practice, rather than as deemed savings though a planning exercises. Doing so reveals the stochastic nature of demand response benefits. It produces benefits estimates consistent with established practices for evaluating initiatives designed to improve market performance. Moreover, this approach is compatible with practices that are being adopted in centrally

[2] DOE 2006, op cit.

organized markets, which we understand the SPP intends to establish, thereby ensuring KCP&L that programs it implements in the near future will deliver enduing benefits.

2. Characterization of Demand

The demand model in PriceFX quantifies changes in electricity usage by retail customers in response to a change in the price they pay (price response), or that are imposed by shutting off specific devices in a demand response program. The level of detail is determined by the extent to which the population of customers can be segmented[3] to reflect differences in the hourly profile and level of usage and price elasticity can be assigned, or level of load control can be attributed. In addition, because price response is defined in terms of a price change, for each segment a reference price must be identified to establish the basis for measuring price changes under dynamic pricing products.

2.1 Customer Segmentation

The KEMA team utilized the customer population and usage reported on the Q4 2005 FERC Form One report as the primary source of data used for customer segmentation. This was augmented by information provided by KCP&L from a more detailed version of the input used to prepare the report, which included the fifth rate code character.

Customers were segmented according to five rate code identifiers used for billing: state, class of service, tariff type, service type and basic business type/voltage level of each customer; plus corresponding rate schedule. Table 2-1 highlights the essential distinctions that define each rate code identifier. Because there was insufficient information to segment customers by business type, demand was modeled in three distinct segments: residential, commercial, and industrial[4].

Table 2-1 Essential Rate Code Definitions

[3] For the purposes of this study we were provided data at the rate class level (residential, commercial and industrial). Research has indicated that there are substantial differences in the level and character of price response among firms engaged in different business activities that are masked at the rate class level. As KCP&L markets its new programs, further market research may prove useful.
[4] See comment above.

Rate Code Identifier	Main selections for identifier
1-State	KS or MO
2-Class of service	Residential, Small General Service, Medium General Service, Large General Service, or Large Power Service
3-Tariff Type	Generally available, special contract, etc.
4-Service Type	Standard, All-electric, Space heat
5-Business class/Voltage	Commercial or Industrial
Level	Secondary, Primary, Substation or Transmission
Rate Schedule	Rate schedule number

Table 2-2 shows FERC Form One customer counts by class of service and state. The total number of customers by state is fairly even, but the number of customers by class of service, service type, and business class varies considerably between Kansas and Missouri. A comparison of the class load shapes, provided by KCP&L, between the two states indicated that there are important differences in class usage profiles. As a result, the demand characterization was made by state.

Table 2-2 Customer counts by class and state

	KS	MO
Residential	205,125	243,297
Small Gen Svc	21,723	26,746
Medium Gen Svc	3,864	4,852
Large Gen Svc	2,205	1,140
Large Power Svc	52	100
Others	3,065	3,743
Unclassifiable	460	-
Total	**236,494**	**279,878**

Customer counts in each state were summarized by rate schedule to identify the appropriate reference rates for each segment for each state. Special service rates, such as street lighting and sales for resale were excluded. Table 2-3 shows the number and percentage of customers by state that were excluded, which amount to only 2-3% of the total population.[5]

Table 2-3 Percentage of customers not modeled

	KS % not modeled	MO % not modeled
Residential	0%	0.03%
Small Gen Svc	8.56%	8.61%
Medium Gen Svc	9.08%	7.52%
Large Gen Svc	58.50%	4.47%
Large Power Svc	0.00%	0.00%
Others	0.00%	0.00%
Unclassifiable		
Total	**2.97%**	**2.31%**

Table 2-4 shows the customer counts and total annual MWH for modeled rates by rate schedule and three-character rate code. Non-residential customers were characterized as commercial or industrial and then by sorted by voltage level within each business type. To facilitate modeling commercial and industrial customers, a single voltage level was used to determine the default rate for customers of a specific class size. For example, all Small General Service customers were assigned to the Secondary service level default rate, even though some may actually be billed for service at primary voltage. The voltage level selection for each class was based on the total annual MWH of the class.

[5] Street lighting accounts included in the LGS class in Kansas account for over half the account numbers, but only a small faction of total class load.

Table 2-4. Customer counts and annual MWH for modeled default rates

RATE SCHEDULE			Customer Count		2005 Annual MWH	
KS	*MO*	*Tariff Sheet*	KS-COUNT	MO-COUNT	KS-TOTAL MWH	MO-TOTAL MWH
		LGA-COMM TOTAL	***210***	***228***	***502,741***	***783,262***
46	19	***LGA-INDUS TOTAL***	***11***	***8***	***28,007***	***33,925***
45	18	***MGA-COMM TOTAL***	***300***	***448***	***83,102***	***134,273***
45	18	***MGA-INDUS TOTAL***	***7***	***16***	***3,009***	***4,865***
44	17	***SGA-COMM TOTAL***	***1,355***	***592***	***18,230***	***18,674***
44	17	***SGA-INDUS TOTAL***	***11***	***10***	***146***	***572***
31	9	***SGS-COMM TOTAL***	***17,703***	***23,175***	***270,234***	***400,669***
31	9	***SGS-INDUS TOTAL***	***794***	***665***	***15,296***	***13,851***
32	10	***MGS-COMM TOTAL***	***3,059***	***3,697***	***548,719***	***749,601***
32	10	***MGS-INDUS TOTAL***	***147***	***326***	***25,583***	***59,572***
33	11	***LGS-COMM TOTAL***	***630***	***718***	***976,248***	***1,078,188***
33	11	***LGS-INDUS TOTAL***	***64***	***135***	***100,686***	***212,718***
34	14	***LPS-COMM TOTAL***	***32***	***57***	***431,272***	***792,341***
34	14	***LPS-INDUS TOTAL***	***19***	***31***	***259,201***	***1,125,827***
16	8	***Res. TOD (TE1A)***	***56***	***-***	***1,033***	***-***
11B	0	***Res. Wtr Htr-1Mtr (RW1A)***	***4,037***	***-***	***53,614***	***-***
11C	5B	***Res. Spc. Ht 1Mtr(RS6A)***	***34,959***	***26,884***	***532,554***	***363,661***
11D	5C	***Res. 2 Mtr Sub (RS2A & RS3A)***	***1,472***	***11,645***	***20,554***	***169,035***
11E	0	***Res. Wtr Htr-2Mtr (RW2A)***	***11,793***	***-***	***211,364***	***-***
11A	5A	***Residential-Gen Use***	***152,808***	***204,767***	***1,980,024***	***2,048,919***
		TOTAL MODELED CUSTOMERS	229,467	273,402	6,061,618	7,989,955

2.2 Price response measures

The characterization of demand by customers of KCP&L for program modeling and valuation required the assigning of a *price elasticity* to each customer segment for each pricing plan evaluated. Price elasticity measures the intensity of the changing usage that a change in price induces. The pricing plans evaluated in the study are distinguished by energy ($/kWh) prices that vary over the day. In the case of time-of-use (TOU) and variable peak pricing (VPP) plans, the distinction is between peak (afternoon) and non-peak (the rest of the day) prices. Prices in RTP can vary among all of the hours of the day. The goal of price-response programs, such as these, is to improve the linkage between wholesale and retail commodity prices. Under these pricing plans, customers can realize savings by shifting usage from the high price periods of the to lower price periods.

Accordingly, price response is best represented through a *substitution elasticity* that measures the change in the peak period load to off-peak load relative to the off-peak to peak price ratio. It recognizes that electricity pays an important and fundamental role in people's lives and is essential and not easily substituted input to business activity. The recent California pricing pilot evaluation reported substitution elasticities for residential and commercial customers, and several recent studies of industrial customer behavior under time-differentiated pricing employed the substitution elasticity. Therefore, substitution elasticity is an important part of measuring the impact of price response.

However, studies conducted to provide a more in-depth characterization of price response indicate that some customers respond to time-based pricing by curtailing discretionary loads for short periods that coincide with high prices.[6] Many customers that participate in programs that pay customers to curtail during specified periods (and otherwise they pay traditional time-invariant electricity rates) also indicated that some of their response is to reduce discretionary load. To take this behavior into account, the RTP price response (the reduction in usage in the high priced hours) was calculated using the substitution elasticity, but only 75% of that was assumed to be shifted to other times; the rest is treated as curtailment of discretionary usage.

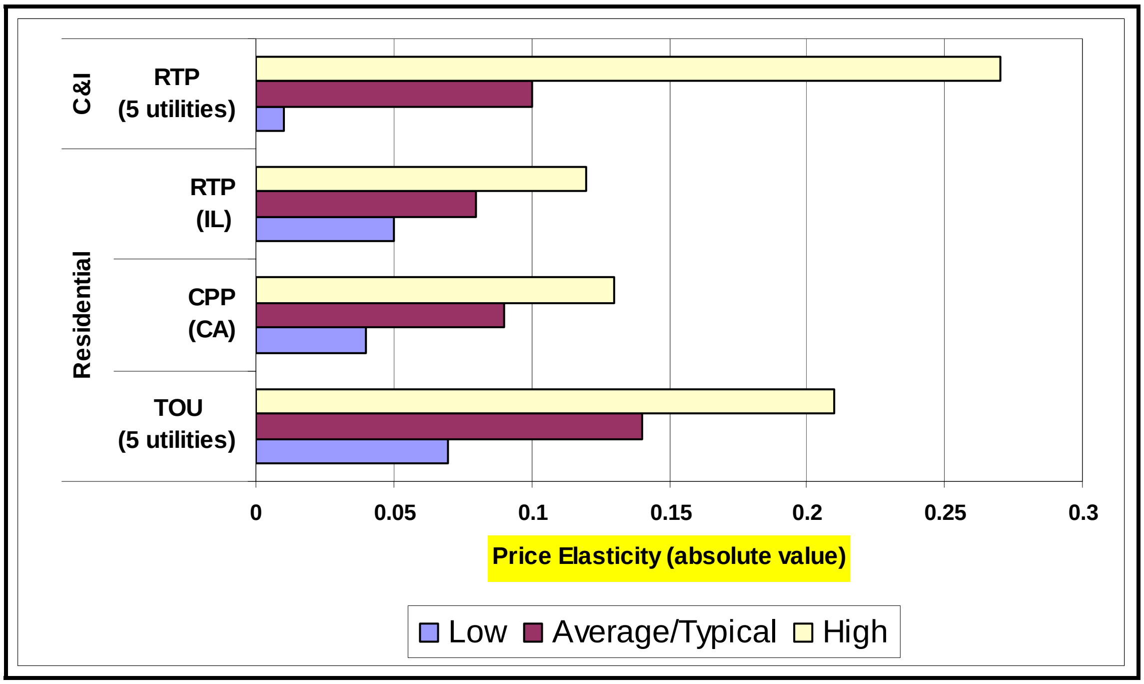
The KEMA team also reviewed available studies that provide estimates of price response to obtain a range of response by customers.[7] A recent DOE report reviewed estimates of price elasticity derived from a formal estimation of the underlying demand curve, which ensures that

[6] Goldman, C., Hopper, N., Bharvirkar, R., Neenan, B., Boisvert, R., Cappers, P., Pratt, D., Butkins, K. 2005. Customer Strategies for Responding to Day-Ahead Hourly Electricity Prices. Demand Response Research Center. Lawrence Berkeley National Laboratory Report No. LBNL-57128. Available at http://www.lbl.gov/:

[7] See Appendix A for a list of studies reviewed.

demand response characterization is logically consistent with consumer and firm behavior.[8] Figure 2-1 illustrates the range of value the DOE report cited. The range of reported elasticity values is largest for commercial and industrial (C&I) on RTP, from near zero to almost 0.28. The variability among residential TOU values is less, but still is a factor of two and a half.

Figure 2-1. Price Elasticity Ranges by Rate Type and Customer Class



Given paucity of studies on price elasticity, that, in particular, include systematic analysis of non-price effects such as customer experience, the availability of control devices, weather, etc., makes assigning price elasticities to KCP&L customers a speculative exercise. Most KCP&L customers have no direct experience with time-varying electricity prices. Many probably already

[8] U.S Department of Energy. February 2006. The Benefits of Demand Response in Electricity Markets and Recommendations for achieving Them. A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005.

have latent price response capability because they have flexibility in how they use electricity during the day. But, until they actually face prices that change, they themselves may not be able to recognize that capability. Moreover, customers with similar circumstances, for example commercial office facilities, may exhibit vastly different levels of price response due to important differences in the facility and how it is used, the level of business activity, and the inclination of managers to undertake price response given the expected benefits.

In order to characterize price response for this study, the KEMA team assigned a price elasticity for each segment by pricing plan. The elasticities assigned reflect the average level of price response from the studies reviewed. We, then, assigned low and high boundary values. The mean values are used to reflect the expected value. The boundary values are provided to support simulation conducted to explore the implications of encountering lower mean price response levels that others have reported and higher values that might be associated with a more mature program that combines customer experience with the adoption of enabling technologies to achieve greater response.

Since participation in the proposed pricing programs would be voluntary, this level of price response is applicable to those customers that find participation potentially rewarding; those who, at least, believe that they could do better in the time-varying rate than on the conventional tariff. Therefore, the elasticities are not representative of the price elasticity of the entire population if such programs where made mandatory. In order to provide a meaningful representation of the potential contribution of price response programs to the KCP&L demand response portfolio, the KEMA team established participation rates are consistent with the experience in other markets, and research on customer preferences for price response programs. We assumed 20% of the Residential sector, 25% of the Commercial sector, and 50% of the Industrial sector would be amenable to these time-varying rates. Program participation rates for TOU, VPP, and RTP were then developed based on two conjoint studies of customer preference for pricing products and the team's experience with these types of rates. These assumptions are shown in Table 2-5.

Table 2-5. Price Response Measures and Participation Rates

Customer Class	Retail Rate	Elasticity of Substitution	Participation Rate
RES	Default	0.00	80%
	TOU	0.10	10%
	VPP	0.04	5%
	RTP	0.04	5%
COM	Default	0.00	75%
	TOU	0.13	15%
	VPP	0.07	5%
	RTP	0.07	5%
IND	Default	0.00	50%
	TOU	0.21	5%
	VPP	0.16	15%
	RTP	0.16	30%

In summary, we categorized customers in both Kansas and Missouri as residential, commercial or industrial thereby creating six segments for which a price response characterization. An 8,760 hourly load profile was established for each segment. Customers in each segment were distributed to one of four pricing plans as shown in Table 2-6. The four plans being:

- Currently available rate (default)
- Time-of-use (TOU)
- Variable Peak Pricing (VPP)
- A Real-Time Pricing (RTP)

Descriptions of the time sensitive rates may be found in Section 4.

Each segment and pricing plan combination was then assigned an elasticity equal to mean estimated price elasticity reported in studies of pilot, experimental or full-scale implementation pricing programs. The result is nine mutually exclusive segments of the KCP&L customer population. These segments provide the basis to characterize portfolio price response.

Table 2-6 Customer Participation Statistics by State and Rate

	Kansas			Missouri		
Retail Rate	Customer Count	Total Energy	Total Peak Demand	Customer Count	Total Energy	Total Peak Demand
Default Rate	182,086	22,923,787	1,217	216,914	28,825,348	1,382
TOU	24,052	3,633,748	184	28,721	4,624,574	212
VPP	11,568	1,741,223	88	13,780	2,732,688	118
RTP	11,727	2,075,023	100	13,959	3,830,720	154
Total	**229,433**	**30,373,780**	**1,589**	**273,374**	**40,013,330**	**1,866**

3. Characterization of supply

3.1 Marginal energy costs

KCP&L provided several sources of pricing data to characterize system marginal supply costs over the next five years. We first looked a the recent price topography to gain an understanding of KCP&L's recent experience and then developed yearly estimates of expected marginal costs using information provided by KCP&L's MIDAS system.

In the first view, KCP&L provided system lambda data for the period of January 2, 2005 – August 31, 2006. The marginal cost of energy to serve the next MW of load as determined by day-ahead scheduling is identified as "system lambda". According to the KCP&L staff, "system lambda" is the greater of KCP&L trader's expectations for hourly prices the following day and a unit commitment model that would seek to maximize the value of off-system sales. The data were broken out into price buckets to characterize the distribution. As illustrated in Table 3-1, 85% of the hours were below $50/MWh, with over 97% of the hours were below $100/MWh. There were only 0.2% of the hours with prices over $200/MWh, and no price exceeded $300/MWh.

Table 3-1 System Lambda Price Distribution

Price Range	# of Hours	% of Total	Cumulative
$0 - $50	12,430	85.5%	85.5%
$50 - $100	1,750	12.0%	97.5%
$100 - $150	282	1.9%	99.4%
$150 - $200	52	0.4%	99.8%
$200 - $300	29	0.2%	100.0%
$300 - $400	0	0.0%	100.0%
$400 - $500	0	0.0%	100.0%
$500 - $750	0	0.0%	100.0%
$750 - $1000	0	0.0%	100.0%
$1000+	0	0.0%	100.0%
Total	14,543	100.0%	

In the second view, the same analysis was based on KCP&L's current RTP rate. Our understanding, based on information provided by and discussions with KCP&L staff, is that the existing RTP rate is comprised of marginal energy cost, marginal outage cost, and the effective energy cost. KCP&L also provided RTP price data for the secondary voltage level.[9] As shown in Table 3-2, a review of the distribution of RTP prices shows the effect of including the marginal outage cost – prices are systematically higher than the system lambda prices for the same time period. Only 44% of RTP hours have prices of $50/MWh or less, in comparison to the 85% for the system lambda data. 92% of the hours exhibit RTP prices less than $100/MWh, only 5% less than that for system lambda values. However, there are several hours when RTP prices reached relatively high levels. Roughly 1.5% of the hours had prices in excess of $300/MWh, and there were 33 hours where RTP prices exceeded $750/MWh. This type of price volatility should induce customers to cut back on consumption in order to avoid such high prices. However, since the current RTP prices are not reflective of the KCP&L's marginal costs as shown by the comparison with the system Lambda, there is a strong disincentive for anyone to participate in the RTP program as it is currently designed.

Table 3-2 RTP Price Distribution

Price Range	# of Hours	% of Total	Cumulative
$0 - $50	6,394	44.0%	44.0%
$50 - $100	7,031	48.3%	92.3%
$100 - $150	650	4.5%	96.8%
$150 - $200	130	0.9%	97.7%
$200 - $300	131	0.9%	98.6%
$300 - $400	65	0.4%	99.0%
$400 - $500	46	0.3%	99.3%
$500 - $750	63	0.4%	99.8%
$750 - $1000	32	0.2%	100.0%
$1000+	1	0.0%	100.0%
Total	14,543	100.0%	

[9] RTP prices are slightly different at different voltage levels to account for losses associated with stepping down the voltage.

Of course, the period of concern is the period 2007 – 2011. Therefore, in order to provide a characterization of future marginal prices, the KEMA team worked with KCP&L counterparts to determine if its MIDAS system could provide hourly price forecasts for that period. MIDAS is used by KCP&L to perform medium to long-term planning studies. MIDAS contains a characterization of the generation units and transmission system of the entire Eastern Interconnection. It is used by KCP&L to understand how changes in KCP&L load, plant and transmission availability, and other stochastic inputs influence supply costs prices and support capacity planning exercises. KCP&L provided us with its most recently completed planning study, in which 35 different MIDAS runs were executed for the period of 2006 – 2011. Each run involved sampling from distributions of key inputs to derive a point estimate of each that the MIDAS model then utilizes to determine resulting minimum cost dispatch and the resulting marginal supply costs. Together they represent a characterization of the range of marginal supply costs that KCP&L might encounter over the period 2007-2011. However, in order to evaluate the proposed demand response portfolio, in particular to ascertain the value of the portfolio in years where high costs produce adverse results for consumers, the individual simulations must be categorized either by their probability of occurring, or by the severity of the prices produced.

KCP&L staff indicated that the MIDAS system assumes that each month's supply characterization is independent but there are some temporal interdependencies within a simulation run (i.e. fuel price forecasts). For this reason, the KEMA team determined that is was not appropriate to choose all the worst months across the different simulation runs, nor choose the worst years in a similar fashion as this would remove the stochastic representation and independence of inputs, necessary to construct the worse-case scenario. It seemed more prudent to let each simulation run stand alone as a complete object, and then chose the results from the 35 runs that we felt best represented the price topologies of interest. The simulation runs were ordered by the overall standard deviation of their prices[10] as a way to provide some insight into the lower and upper bounds of benefits, as well as those representative of the median outcome. The run with the highest standard deviation was chosen to represent the case when prices are at their most volatile (High scenario), while the run with the lowest standard deviation was chosen to represent the case when prices are as stable as possible (Low scenario). We opted to use the median run to represent the most likely price topology for the period of 2007 – 2011 since producing an average scenario seemed ill-advised given the unique distributions of each simulation run and not knowing the relative probabilities of the chosen input values. The price distributions of each scenario are depicted in Figures 3-1 through 3-5.[11]

[10] Since it is the prevalence of price spikes that will drive the benefits of more price-responsive retail rates, the standard deviation was calculated for each simulation run to show how prices over the 6 year period varied about the mean value.

[11] These price forecasts generally show a clear upward trend in the near-term, but decrease in the 2010 to 2011 time period. Based on information provided by KCP&L concerning its capacity situation, the system is anticipated to run short of required capacity reserves over the next several years, but will then have an excess of generating capacity in the remaining years of our study period. This is one known factor that could explain the change in the level and volatility of prices over the five-year study period, but clearly the stochastic nature of MIDAS represents additional (unknown) reasons for this phenomenon based on the chosen random inputs for these three chosen runs.

Figure 3-1 2007 Simulation KCP&L Price Topology

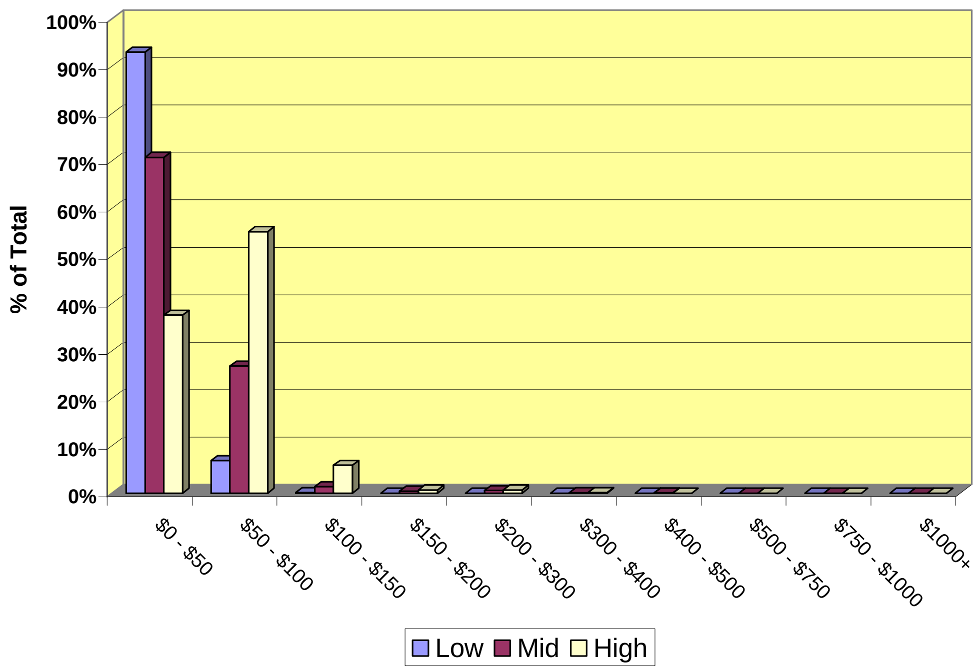


Figure 3-2 2008 Simulation KCP&L Price Topology

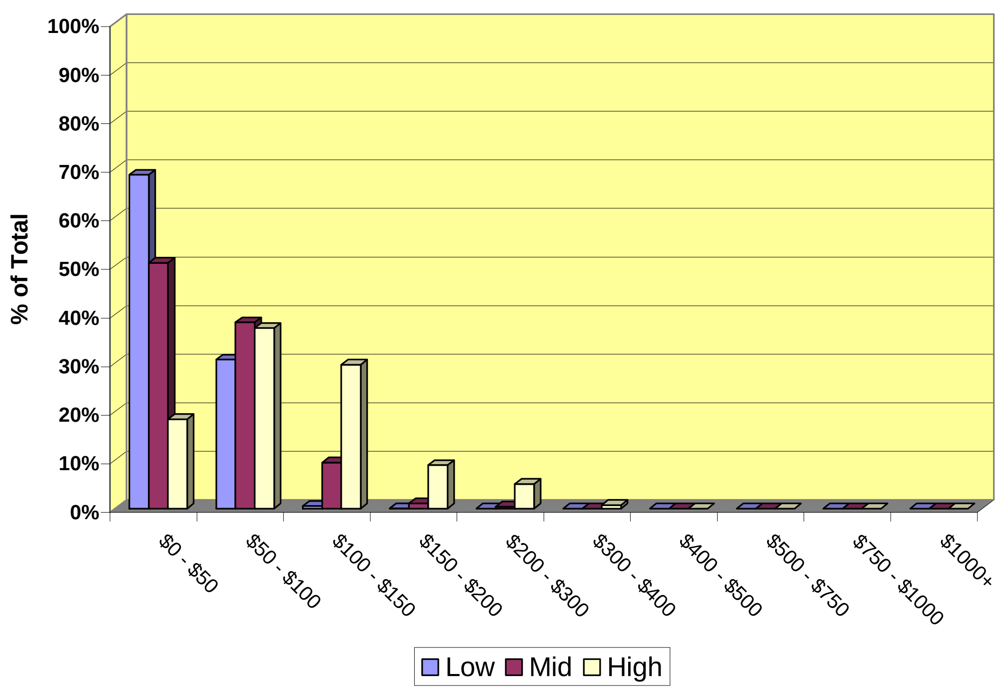


Figure 3-3 2009 Simulation KCP&L Price Topology

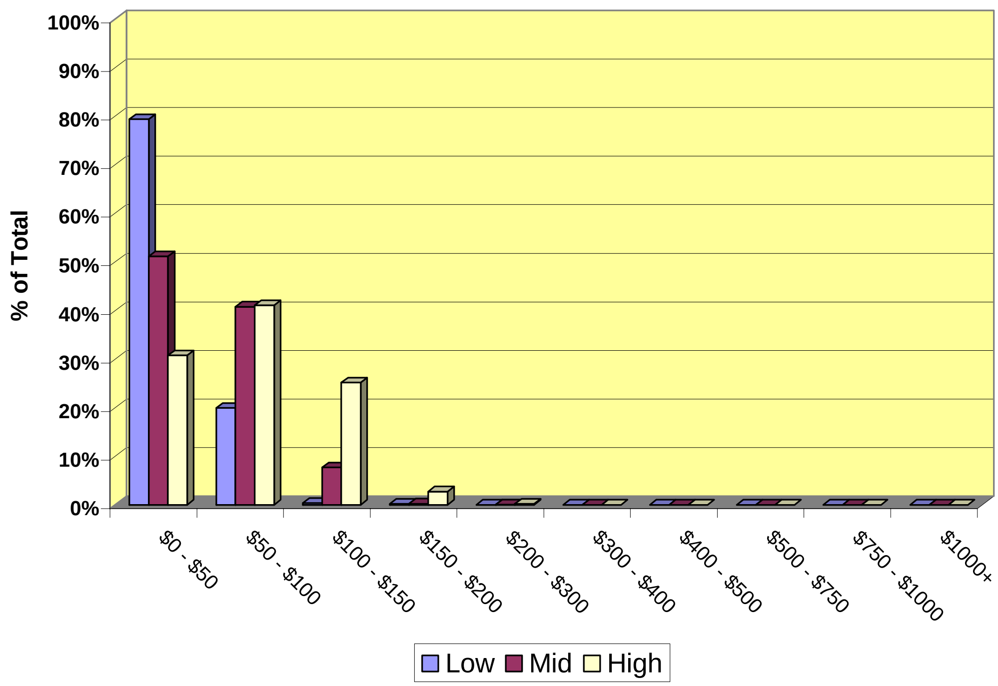


Figure 3-4 2010 Simulation KCP&L Price Topology

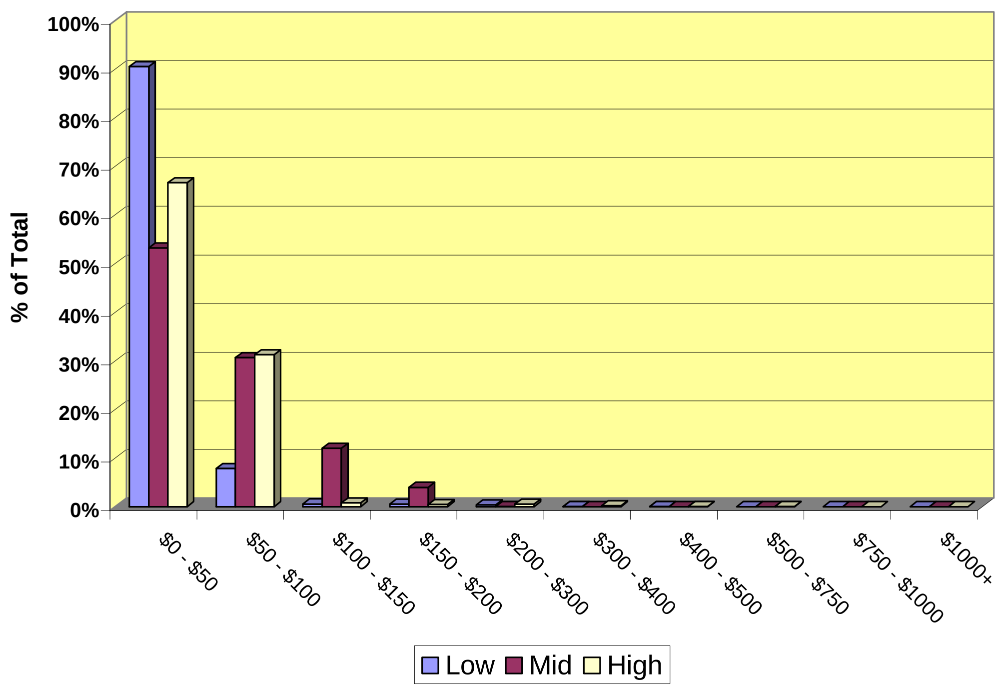
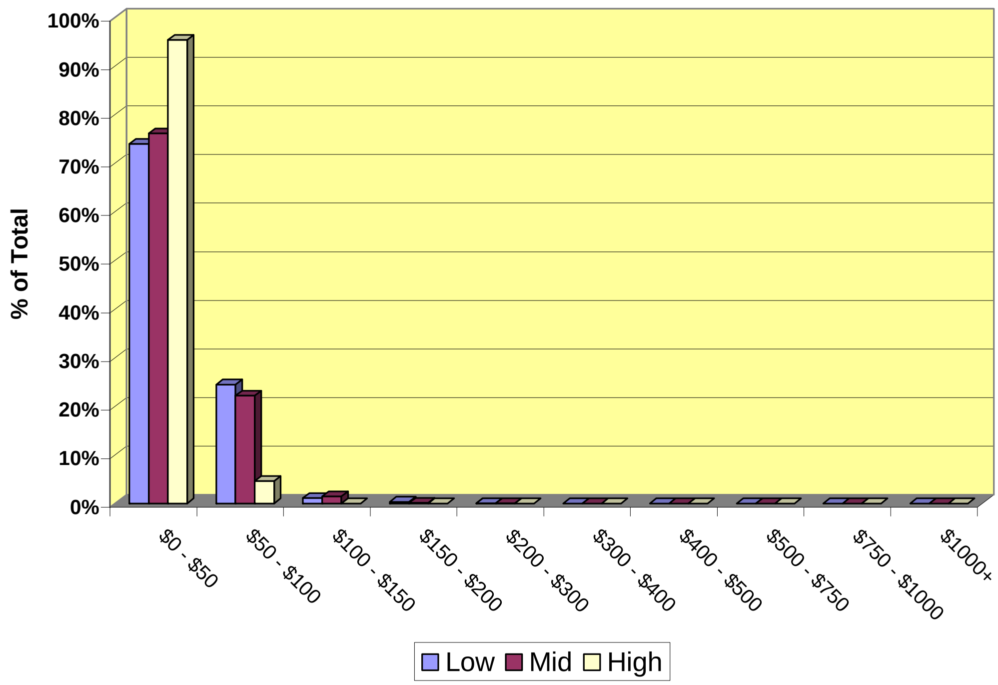


Figure 3-5 2011 Simulation KCP&L Price Topology



3.2 Marginal capacity costs

KCP&L is projecting a capacity shortfall between 2007 and 2009, but sufficient or surplus capacity in 2010 and 2011 (and beyond) if the Iatan generating station is on-line. NERC requires all utilities to have sufficient planning reserves to cover forecasted load plus a margin to cover unexpected generator outages, unanticipated load growth, or other such contingencies. KCP&L provided four different estimates for the marginal cost to procure capacity over the five year period covered by the study, which are listed in Table 3-3. The first (KCPL) is an internal estimate of the cost to procure installed capacity externally specifically for delivery into KCP&L's control area, which ranged between a high of $26.69/kW-Year (2007) to a low of $16.50/kW-Year in both 2010 and 2011. The second set of values (SPP) reflect SPP's estimate of the average capacity cost in its footprint, without regard to where it is delivered., which are lower and somewhat more stable, showing a slight rise over the 5 year period (17.37/kW-Year to $22.06/kW-Year). However, for both of these categories, the estimates are for non-firm capacity, and it not clear that firm transmission rights are available, and if so, what they would cost. . Non-firm resources would likely not be available during at least some critical periods, and therefore they do not provide an equivalent to dedicated, firm network resources. The final estimates represent the cost to build a new combustion turbine. The first (Capacity-Only Cost of a CT) is the levelized annual debt and equity service cost, which ranges between $41-44/kW-year. The last entry in Table 3.3, All-in Cost of a CT is an annual levelized cost of capital and operating costs, sometime referred to as the avoided costs, which is forecasted to be $61.65/kW-Year. The Capacity-Only cost appears to be the best proxy for the avoided cost of capacity over they study period.

Table 3-3 Marginal Capacity Costs

	Value of Capacity ($/kW-Year)*				
	2007	2008	2009	2010	2011
KCPL	$26.69	$25.48	$25.75	$16.50	$16.50
SPP	$17.37	$19.22	$21.13	$21.40	$22.06
Capacity-Only Cost of CT	$43.74	$43.74	$42.09	$41.42	$42.46
All-In Cost of CT	$61.65	$61.65	$61.65	$61.65	$61.65

* All data provided by KCP&L.

3.3 PriceFX simulation methodology

As described in Section 9, UtiliPoint International, Inc. has developed a state-of-the-art simulation model that integrates customers and their response to time-varying retail rates with a characterization of both the electricity and capacity markets to quantify the level and distribution of benefits associated with such retail rates structures. The model can be broken down into six different areas:

1. Develop a characterization of customers into groups that differ by the current default rate they pay but have similar demand response capabilities;
2. Derive a characterization of the marginal value of electricity and capacity as it varies across the analysis time period;
3. Calculate the different alternative time-varying (price response) retail rates based on the derived electricity market characterization;
4. Predict how customers respond to the new retail rates assuming some proportion of each customer class elects to join one of the alternative rates or remains on the default tariff;
5. Aggregate the change in consumption at the system level on an hourly basis; and
6. Calculate how changes in system load and coincident peak demand would have affected the marginal price of energy and the amount of capacity that must be procured in the future.

The *PriceFX* model relies on a characterization of demand and supply that produces the likely range of benefits associated with introducing price-response retail rates rather than Monte Carlo simulation employed in some approaches. It is possible to understand the tradeoffs between expectations and realizations of both sets of characterizations using sensitivity analysis.

3.4 Measures of Benefits

There are several benefits streams can be quantified as result of customers altering their consumption in response to signals provided by a price or demand response program. They are:

1. **Participant savings**: Those customers electing to be served under a price-responsive retail rate generates bill reductions by eschewing consumption during high priced periods and shifting it to lower-priced periods of the day. Depending upon how the retail rate is designed, participants may or may not also realize an inherent bill savings, relative to the

default rate even if no price-responsive behaviors are undertaken. The latter aspect is acceptable in a rate design because the risk associated with more time-differentiated pricing is shifted from load-serving entities (LSE) to customer.

2. **Increased off-system sales**: When customers curtail usage, it frees up native generation to be offered into the SPP market and sold off-system. However, such sales so not always result in windfalls to the LSE. This condition occurs with rates that are not directly tied to the market prices, like time-of-use (TOU) rates or Critical Peak Pricing (CPP). If program participants undertake load reductions in response to their retail rate but the market values for the now available electricity is at a lower price, the LSE makes less on the off-system sale then it would have made selling this electricity to the participant, had the customer actually consumed the electricity.

3. **Reduced bilateral costs**: Reductions in demand put downward pressure on marginal electricity prices. If these load curtailments are sufficient enough, price volatility can be significantly mitigated while also reducing overall level of prices. Such short-term price reductions can and should have a noticeable impact on the procurement of supply in the long-run, via downward pressure on bilateral contracts. In a vertically integrated utility, this will mean reduced average costs and should translate into lower retail rates if such price response efforts are sustainable.

4. **Deferred Capacity Costs**: To the degree that price-response reduces the coincident peak, upon which capacity requirements are often times based, the costs associated with procuring sufficient capacity to meet reserve margins should be reduced. Lower coincident demand in one year should translate into lower capacity obligations the next year, *ceteris paribus*.

5. **Change in Net Social Welfare**: Economists see most of the aforementioned benefits as mere transfers: money moving from one hand to another. However, changes in the structure of retail rates that offer customers the opportunity to make more efficient consumption decisions by paying prices that are more representative of the marginal cost

of supply make society as a whole better off. By quantifying the change in consumer and producer surplus, it is possible to estimate the change in net social welfare.

4. Program Portfolio

To address KCP&L's need for a portfolio of price response and demand response programs, the KCP&L team proposes the following programs for the customer groups listed below.

4.1 Portfolio Development and Optimization

Table 4-1 Summary of Proposed Programs

Program/Class	Residential	Small GS	Medium GS	Large GS	Large Power
Pricing Programs					
RTP	√ - new	√ -new	√ -new	√ -revised	√ - revised
VPP	√ - new	√ -new	√ -new	√ -new	√ - new
TOU	√ - revised	√ - revised	√ - revised	√ - revised	√- revised
Reliability/Capacity Programs					
DLC Plus	√	√			
VLR Plus			√ - revised	√ - revised	√ - revised
MPOWER Plus			√ - revised	√ - revised	√ - revised

As described in the Introduction of this report, the KEMA team established four principles to guide the process:

- Sustainability with current and future markets
- Predictability of results
- Cost-effectiveness
- Utilization of proven platforms for program designs

Sustainability refers to the need to design programs that are consistent with the overall market design. In the case of SPP there is uncertainty as it is under development, and its final design is not evident. We understand that the apparent preference by stakeholders is for a wholesale market design that is very light-handed, and that might limit the role of spot energy markets and the extent to which SPP imposes capacity requirements on load-serving entities. The KEMA team is aware that there is no explicit recognition by SPP of such resources as playing an integral part of its market planning or operational obligations. However, precedent has been set in the northeast ISOs and elsewhere for integrating both price and demand response directly into ISO operations in ways that provide equivalent value to what generation is paid. Therefore, the final design may involve more rigorous legerdemain by SPP and an RTO. Consequently, the KEMA team selected designs for demand response programs that have been adopted in other ISOs with more structured markets, so that KCPL can expect that it gets the full value from demand response resources it contracts for with its customers through tariffs, and that these arrangements would be compatible with programs SPP, itself, would likely promulgate. That being said, we urge KCP&L to immediately begin immediately to engage SPP in discussion to determine what role demand and price response play will ISO operations, and define the corresponding protocols, so that optimal value can be achieved from KCP&L price and demand response programs.

Predictability refers to the expected level of price or demand response foreseeable within reasonable error bounds. Both SPP and KCP&L schedulers and dispatchers must be able to forecast the program participants' response in order to fully and effectively incorporate demand diversity into system operations. Despite over 35 years of experience with demand and price response by hundreds of utilities, as the recent DOE study revealed, there has been startlingly sparse systematic evaluation of what product features drive customers to participate and their relative impact is the participation decision. However, there is a growing body of information about price response that appear to provide a converging perspective on event performance.

Consequently, the KEMA team focused on basic price and demand response designs wherein price or a proxy thereof (for example a penalty or incentive) is the primary feature specifically used to get customers to focus on the primary value proposition: incentives in return for undertaking more risks than traditional rates require. Thus, the demand response programs utilize very fundamental designs that are stripped of secondary features, like event limits, varying notice or event duration provisions, and tradeoffs between contract term and the level of benefits offered. There is no conclusive information on how these features affect participation, although clearly customers prefer more benefits for less risk. Moreover, differentiating price and demand response products creates the need to develop consistent variations in benefits, the achievement of which is not straightforward. Finally, increased complexity in program design increases the risk that the programs are incongruous with SPP valuation criteria.

Cost-effectiveness, in the context of price and demand response programs, requires that net benefits associated with implementing the programs exceed the costs of doing so. We utilized protocols for quantifying the level and distribution of benefits that FERC has accepted for assessing the performance of pricing and demand response programs implemented by ISOs under its jurisdiction. These protocols have also been used by regulators and agencies in several states to guide their policy-making endeavors, as well as by utilities and retailers to design effective and profitable programs. The protocols quantify the important economic and financial benefits that can be expected from these programs under a variety of circumstances to provide a forward view of program performance and value. KCP&L may identify other financial benefits, such as operational savings, economies of scale and scope, especially with DSM and economic development programs, and externalities that can be translated, albeit subjectively, into monetary benefits. As these benefits become known they may be added into the business model. In summary, the overarching goal should be to quantify benefits as, predictably, thoroughly and precisely as possible and compare them to the cost of developing and administering a portfolio of programs.

We developed the portfolio using from *proven platforms* that are compatible with, or can be easily adapted to, current and foreseeable market designs. Many of these platforms have already been adapted in some degree by KCP&L which indicates that their planners have, in the past reached similar conclusions. That does not mean, however, that the portfolio cannot be significantly strengthened by changes in design. The proposed pricing and capacity plans included in this document do, in some cases, involve rather modest changes in design features, as is the case with Optimizer. In other cases such as MPOWER, and VLR, however, the KEMA team has proposed substantial design modifications to achieve the goals of sustainability, predictability, and cost-effectiveness.

In the end, the portfolio is designed to balance achievement of increased efficiency with higher reliability at a lower cost. Price response programs, such as real-time pricing (RTP), variable peak pricing (VPP), and time-of-use pricing (TOU), address improved overall sector efficiency. That is, by linking retail usage prices directly to marginal supply costs, customers are induced to consume electricity wisely. Since electricity supply costs vary by hour, time differentiated pricing (RTP, VPP, and TOU) provides customer the incentive to use less during higher cost periods, thereby, potentially relieving system peak loads and constraints, and, at the same time, the rates encourage customers to more when electricity is cheaper. Flat rates, on the other hand, have no such incentives.

Demand response programs, such as direct load control (DLC), like KCP&L's Optimizer, and interruptible and curtailable (I/C), like MPOWER if properly designed and implemented reduce overall cost of meeting capacity adequacy requirements and increasing consumer surplus. Emergency programs supplement operating reserves and thereby provide insurance against the adverse consequences of forced outages. Utilizing dispatchable load as a capacity resource requires that local reliability protocol accept that such loads can be counted to meet adequacy reserve requirements. The full value of emergency programs is realized when resources are dispatched by the regional system operator that has responsibility for reliability, and is the position to determine when such resources are needed. To sustain these programs in the longer term, support from SPP may be required. However, with state regulatory approval, KCP&L and its customers can receive benefits from these programs in the near term.

A key point for KCP&L to keep in mind is that the portfolio is designed to offer specialized demand and price response programs that were effective in achieving efficiency or providing equivalent capacity resources, respectively. In Figure 4 – we summarize our position on what programs best serve what purposes. The KEMA team position is that no single rate design or program can effectively accomplish both because the provisions that would be required to do so would be confusing to customers and difficult for the utility to administer. The price response programs all are designed on the principle that the seller establishes a price and the buyer decide how much to buy. Doing so ensures a competitive equilibrium whereby price serves to clear the market, whereby supply and demand are balanced, under all but exceptional circumstances. At times, conditions conspire to make it difficult or even impossible, to balance supply and demand and maintain supply contingency consistent with accepted reliability standards. It is these times that price can not serve it usual role. Conditions change too fast for prices to be conveyed and consumers to react. Demand response program are designed to achieve supply rationing to balance supply and demand with acceptable reliability margins. So program do so using price incentives, but those prices are predetermined and established specifically to achieve a desired outcome with regard to load reductions.

Figure 4 – Matching Program Design to Need

Utility Need	Most Effective Program Response
Substitute for Capacity	Direct payment to customer for load reduction consistent with RTO/ISO rules
Mute volatility and demand during periods of very high marginal costs	Pricing programs such as real-time, time-of-use, critical peak or other dynamic prices linked wholesale market prices
Auxiliary reserves to avoid forced outages	Voluntary, pay on performance, load curtailment programs.

The KEMA team believes that by designing program specifically to one job or the other effectively and practically balances the need to have resources available that can be counted on at times while letting customers make consumption decisions at other times. Doing so also recognizes the diversity of customer situations and inclination to manage their electricity usage. Some want command and control at all times. Others want security, but are willing to surrender control in the interest of maintaining system reliability. By letting customer not only chose between price and demand response plans, but letting them subscribe to one of each, the proposed portfolio achieves KCP&L's desire to use these programs to resolve operational situations and further KCP&L's commercial interests.

4.2 Proposed additions to portfolio

4.2.1 Price Response Programs

Table 4-2 provides an overview of the key features of the proposed Price Response Programs for the KCP&L portfolio.

Table 4-2 Price Response Program Features

KCPL Proposed Price Response Programs			
Feature	**Proposed RTP**	**Proposed VPP**	**Proposed TOU**
Eligibility	***All Customers***	**All Customers**	**All Customers**
Metering	Hourly interval meter	**Hourly interval reads using exisiting meters**	**TOU meter**
Price Postings	Day Ahead by 4:00 pm	**Peak: Day Ahead by 4:00 p.m. Off-Peak: Annually TOU Schedule posted each February**	**Annually - TOU prices posted each February for the following April - March**
Price Formation	**SPP market-based**	**Off-peak price determined by annual marginal cost forecast. Peak price is SPP market-based**	**Determined by annual marginal cost forecast**
Peak Season	N/A	**June 1 - September 30**	**June 1 - September 30**
Peak Period Hours	N/A	**2:00 - 6:00 p.m. weekdays**	**2:00 pm - 6:00 pm weekdays**
Off Peak Period Definition	N/A	All other times	All other times
CBL	***Blocking of hours only if customer and KCPL agree, otherwise hourly***	N/A	N/A

4.2.1.1 Common Features

Price response programs share common features and some differences. For example, TOU and VPP require metering of on and off-peak energy while RTP requires hour-by-hour metering. VPP and RTP share a common daily communication channel or channels to deliver prices. Not the least important common feature is the specification of what the peak season months and hours will be for TOU and VPP. Following is a description of our method for establishing peak season months and hours for TOU and VPP.

To the peak season, we analyzed KCP&L's MIDAS results for hourly prices and system loads from January 2006 through December of 2011. The analysis sought to identify the months and hours in which high prices were observed most frequently, so as to produce a rate whose peak period price was the most representative of comparable wholesale market conditions. We used the results of 35 MIDAS[12] runs covering each year for the period 2006 to 2011 to establish time periods for the TOU and VPP prototypes.

A review of the price distribution for those years we observed that the majority of the time, prices fell between $31/MWh and $65/MWh. The maximum price observed was $1110.21/MWh, and the minimum price observed was $9.75/MWh. Overall, the highest weekday average prices were observed between July and August with January and February following behind. Although January and February had higher average prices than June and September, the maximum price observed for January and February did not exceed $265/MWh, while June and September had maximum prices in excess of $475/MWh. The summer months of June, July, August, and September produce maximum prices ranging between $484/MWh and $1,110/MWh. Each month's maximum price for all scenarios and all years occurred during a week day and never on Saturday or Sunday.

[12] See Section 3 for more details on the MIDAS data.

Table 4-3 Summary of Midas Hourly Prices

MIDAS $/MWh	Average Prices		Maximum Prices	
Month	Overall	Weekday Only	Overall	Weekday Only
January	55.38	59.13	262.17	262.17
February	57.08	60.84	244.75	244.75
March	51.25	54.87	208.23	208.23
April	45.00	48.36	139.13	139.13
May	44.45	47.67	177.84	177.84
June	48.94	52.82	484.25	484.25
July	63.12	69.89	1,110.21	1,110.21
August	63.87	70.70	858.07	858.07
September	45.04	48.20	509.80	509.80
October	39.89	42.92	153.62	153.62
November	42.95	45.99	162.57	162.57
December	49.34	52.85	236.39	236.39

To identify the hours in which the peak period should be defined over, the proportion of intervals in excess of $150/MWh that were captured within each definition of the peak were calculated and evaluated. The results showed that the longer is the peak period, the better is the capture rate but the lower is the average price. There was little difference in the capture rate when the peak began at noon, 1 p.m., or 2 p.m. and when the peak ended at 5 p.m., 6 p.m., or 7 p.m. So, based on Midas data, the peak period could span as long as 1 p.m. to 7 p.m. or as short as 2 p.m. to 6 p.m.

Table 4-4 Midas Summer Weekday Prices

Hour-Ending	Overall Number of Hours	Number of Hours w/ Price > $150/MWh			Capture as % of Overall	
		Overall	June - Sept	July - Aug	June - Sept	July - Aug
1	76,685	5	3	3	0.0%	0.0%
2	76,685	2	0	0	0.0%	0.0%
3	76,685	2	0	0	0.0%	0.0%
4	76,685	2	0	0	0.0%	0.0%
5	76,685	3	0	0	0.0%	0.0%
6	76,685	16	0	0	0.0%	0.0%
7	76,685	216	19	16	0.1%	0.1%
8	76,685	479	68	55	0.2%	0.2%
9	76,685	570	140	121	0.5%	0.4%
10	76,685	690	293	249	1.1%	0.9%
11	76,685	1,054	671	564	2.4%	2.1%
12	76,685	1,524	1,200	1,005	4.4%	3.7%
13	76,685	2,156	1,871	1,572	6.8%	5.7%
14	76,685	2,792	2,511	2,104	9.2%	7.7%
15	76,685	3,165	2,917	2,445	10.6%	8.9%
16	76,685	3,352	3,118	2,623	11.4%	9.6%
17	76,685	3,282	3,004	2,535	11.0%	9.2%
18	76,685	2,729	2,324	1,982	8.5%	7.2%
19	76,685	2,089	1,506	1,301	5.5%	4.7%
20	76,685	1,457	925	794	3.4%	2.9%
21	76,685	1,073	654	562	2.4%	2.1%
22	76,685	591	315	275	1.1%	1.0%
23	76,685	137	79	74	0.3%	0.3%
24	76,685	28	19	16	0.1%	0.1%
Total	1,840,440	27,414	21,637	18,296	78.9%	66.7%

Keeping in mind the need for a large peak/off-peak price ratio needs to be balanced against the KCP&L's need to have adequate coverage for hours that high prices may occur and to accurately reflect marginal costs, we defined the season as weekdays of June through September, to capture 78.9% of the high price hours. If the peak season were limited to only July and August it would cover 66.7% of the hours. Since the goal of these price-response programs is increased pricing efficiency, it makes sense to include June and August given the substantial increased capture rate of high-priced hours. By adding June and September, we have covered close to 80% of the relevant hours.

In addition, the peak period was defined as narrowly as possible: a 4-hour peak period window over this four month peak season and represents approximately 340 hours during the year, or around 4% of the hours of the year, but captures 42.2% of the high cost hours if defined between HE14 – HE17 and gets 41.5% if the start time period is moved one hour later. Adding all other hours in the summer (2,516) or another 29% only captures an additional 36% of the high cost hours. So, clearly the 4-hour window is very efficient at capturing high cost hours, the stated goal of these types of retail rates.

Next, an analysis was completed upon the load data for 2006 through 2011, to see if a similar pattern emerged. The load data indicated that the optimal peak period was one hour later than that shown by the price data analysis, i.e. instead of 1 p.m. - 5 p.m., 2 p.m. – 6 p.m. Since the focus of the programs are to both increase efficiency and reduce capacity requirements, the peak period that best achieves both of these goals was, therefore, established as 2 p.m. to 6 p.m., Monday – Friday, June – September.

Based on the defined peak and off-peak periods, the proposed prices for 2007 are: Peak Season On-Peak period: $0.091/kWh, Peak Season Off-Peak period: $0.040/kWh, and Off-Peak Season: $0.050/kWh.[13]

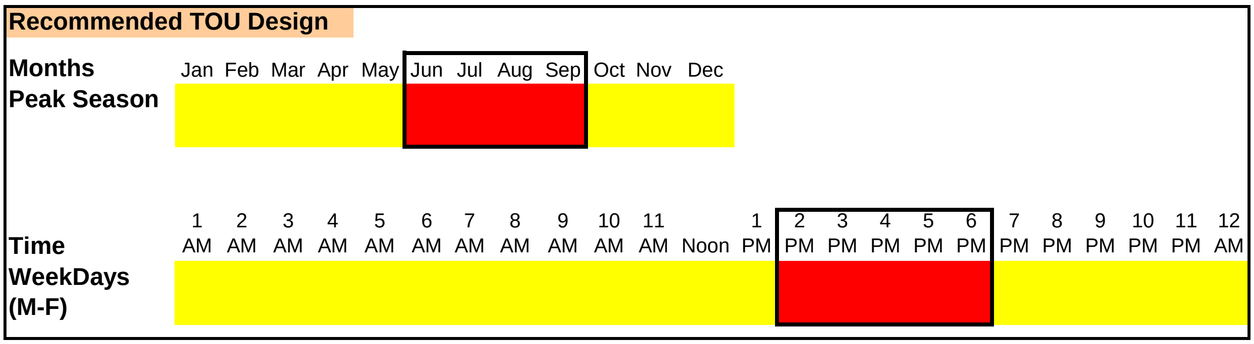
4.2.1.2 Time-of-Use (TOU) - Revised Program

Many customers are unable to wait for each day's prices before they make final electricity consumption plans. Although they may want access to wholesale prices, the inconvenience and price risks make it impractical. But that does not mean that these customers are incapable of exercising some control over usage, especially if the incentives are properly packaged. TOU offers access to wholesale markets, but with the security of list prices. With TOU, the customer knows well in advance what the price will be when he consumes. Therefore, load change and

[13] The TOU, and subsequently VPP, prices used in the simulations are derived from the assumed market supply conditions experienced on an annual basis. It is assumed that the rate-making perfectly predicts actual marginal prices and thus, the marginal prices are reflective of the load-weighted prices in the TOU periods as defined. The rate prices will therefore vary with the different market supply conditions and across years. The prices listed above are for the Mid market characterization in 2007 and are shown as an example only.

shape benefits are assured. Customers looking to reduce their bills will find product options that offer rewards for load shifted from the peak to the off-peak hours.

Figure 4-1 Definition of TOU Peak Season and Period



The proposed TOU program increases the efficiency by tying the peak season and period definition to occurrences of wholesale market prices. As described above, the hourly market price and load forecasts from Midas for the years 2007-2011 scenarios were analyzed to determine the peak season and period that best captured the occurrences of high hourly prices. The months of June, July, August, and September contained the greatest coincidence of high hourly prices and high system load.

Successful TOU programs that provide value to customers are characterized by sound designs combined with substantial marketing. To increase customer acceptance, it is important to understand how customers derive value from TOU plans. Customers benefit by changing behavior to save money. Customers who can conserve during high cost hours, peak period prices that reflect high marginal costs receive the greatest benefit. Customers who can postpone consumption until another time of day, the greater peak price to off-peak price ratio the greater opportunity. Some customers may not desire or be able to alter existing usage patterns, but need opportunities to increase production or comfort during lower cost periods. TOU off peak prices that reflect current off peak wholesale market prices are of greatest value to these customers.

Therefore, to accommodate the variety of customer behaviors, a narrow peak period definition often produces the highest peak period prices and largest peak to off peak price ratio. Under the notion of price elasticity, load response is determined by the change in prices and the intensity with which load is adjusted for such a change. The higher the price change is, the greater the response for a given price elasticity. Some have suggested that there is a threshold price below which customers do not respond and above which price elasticity drive the load reductions.[14] If this is true, that threshold would depend on each customer's circumstances. The KEMA team that such a threshold under a TOU pricing structure is probably at relative price changes of 1.5 to 2. Since the goal of TOU is efficiency, and not to achieve a specified level of load curtailment in a specific period, the proposed prices for the TOU plan reflect the forward hourly price curves provided by KCPL. Therefore, establishing a peak season and peak period definition that accommodates these criteria leads to a TOU program design with a high likelihood of customer acceptance.

4.2.1.3 Variable Peak Pricing (VPP) - New Program

Voluntary Peak Pricing combines the certainty of TOU with the efficiency of RTP. VPP offers access to wholesale markets during peak periods, but with the security of list prices during off peak times. With VPP, the customer will know well in advance what the price will be when he consumes during the off-peak season and off peak period. However, peak period prices are posted a day ahead for the defined peak period and reflect current market conditions. Therefore, load change and shape benefits may be calibrated against current market prices. Customers looking to reduce their bills will find that the ratio of peak-to-off-peak prices, and shift load from the peak to the off-peak hours in respond to the market prices.

[14] For example the DOE Report 2006 op. cit. suggests suggested a peak/off-peak price ratio of at least 3:1 is needed to attract customer interest. The KEMA team believes that such a threshold is probably at relative price changes of 1.5 to 2.

The proposed VPP program is characterized by following the conventions established in the proposed TOU program for seasons and period definitions and uses the equivalent off peak period and season prices. The peak period price is computed and posted daily during the peak season and is comprised of the average of the day-ahead RTP hourly price values for the peak period defined in the proposed TOU program.

4.2.1.4 Real Time Pricing (RTP) – Revised and Expanded

Customers who want the lowest price typically shop wholesale. Real-time Pricing (RTP) is the equivalent to buying of electricity wholesale. RTP subscribers receive daily quotes for hourly prices which reflect wholesale market transaction costs between large-scale generation and distribution companies. These *spot* prices reflect market conditions, and therefore they are subject to considerable fluctuation around their relatively low mean price. Customers who can control their usage find RTP attractive, as it offers relatively low prices most hours of the year. But, they also accept the inherent price risks of buying wholesale; when demand exceeds supply, prices go up to reflect the high marginal value of scarce resources, and unavoidable consumption becomes expensive.

The reward for managing price risks is lower overall electricity costs. RTP is made-to-order for many commercial and industrial customers who can exercise considerable control over how and when they use electricity. As control technologies become more advanced and less costly, more commercial customers, and some residential customers, will be able to utilize RTP to realize greater value from their connection to the electric grid.

Many RTP programs in regulated markets have performed exceptionally well (Goldman, et al., 2005). Some programs have performed poorly due to faulty designs, poor marketing, and poor internal support. The RTP program we propose can lead to substantial success if properly marketed. The variation we propose directly links hourly prices to hourly wholesale market costs and offer a CBL specific to each customer that accurately reflects its typical load shape and level. The CBL is offered as means for making customers initially indifferent, from a cost standpoint, between the default rate and RTP. As will be shown later, the costs to customers of joining RTP without this revenue-neutral design will make recruitment very difficult. The specific RTP program features are as follows:

- Available to non-residential customers
- Prices are available a day ahead by 4 pm
- Annual subscription required
- $Price_h$ = indexed to hourly market prices
- Subscribers can migrate between RTP and VPP without penalty
- The CBL is hourly and represents the customer's historic hourly load shape (is not "blocked")

4.2.2 Demand Response Programs

The programs recommended are a direct load control (DLC) program, a capacity resource program, and a voluntary emergency resource program. Demand response programs should be measured and valued on a consistent basis since loads curtailed delivers equal value per kW, regardless of the scale at which they are delivered. In other words, demand reductions from smaller customers provide equivalent gross benefits as those from larger customers.

Valuation of capacity program is based on the need for reserves (planning and operational) and the cost of additional delivered capacity in the wholesale market. KCP&L's avoided cost of (currently $61.65 per kW-year for a new combustion turbine) forms the foundation of the demand curve constructed to value programs. The VLC program derives it value from the value of avoiding forced outages. A summary of the proposed demand response programs and their features are listed in Table 4-5.

4.2.2.1 Demand Response Program Features

Demand response programs share many program features. For example, subscribers to demand response programs need hourly metering. Programs generally have terms that establish event notice, event duration, event frequency, compensation for event compliance, and penalties for non-compliance.

Experiences show that shifts in the DR supply curve in response to different prices are the result of systematic and observable factors such as:

1. The customer's expectation of how many curtailments must be endured as the cost to curtail is a function of the number of curtailments;
2. The effort spent contacting customers, helping them understand the value proposition, preparing curtailment plans and costing them out ; and
3. Customer experience and the collective market experience. As customers get involved they become more knowledgeable and refine their costs estimates for curtailments so they are not so variable, and as a result the supply curve for DR is more predictable.

SCR – A Benchmark Program

To illustrate how these factors interact the following is a discussion of a program implemented NYSIO called the Special Case Resource (SRC). As will be described in later in this section, we have recommended many of the features of SCR be incorporated into MPOWER Plus. That being said, SRC also represents a well- developed and mature program that can serve as a benchmark for what KCP&L can achieve with MPOWER Plus. Under SCR, end-use customers are allowed to offer their pledged load as a capacity resources to load serving entities (LSE), which are required to acquire generation capacity requirements equal to 118% of their deemed peak load. Customers can sell their SCR capacity directly to LSEs. Such transactions are not reported, so little is known about the prices involved. However, since 2001 customers alternatively were allowed commit SCR resources to the deficiency auction administered by NYSIO. LSEs that are capacity short submit their shortfall to the auction and agree to pay the market -clearing price to fill that need. The auction takes bids to supply capacity, including SCR resources and stacks them in order from lowest to highest cost and determines the last resource requires to meet the demand amount submitted, and set the auction-clearing price at the bid for that marginal supply resources.

The deficiency auction is a spot auction, and provides the means for establishing prices for SCR resources. Because these prices are posted after every auction, they inform both buyers of capacity and sellers of SCR of the value of such resources, and, therefore, bilateral prices are influenced by the spot auction prices. If auction prices are high, SCR sellers will hold out for higher bilateral prices, expecting that if they can't reach a deal, they will get that price in the auctions. The same holds for buyers. The auction and its transparent prices discipline the market so that capacity prices tend toward the marginal cost of supply, which is the most efficient outcome.

The SCR program has grown significantly since its inception with committed capacity growing from 336 MW of resources in 2001 to 1,084 MW in 2006. The latter amount equates to roughly 3.5% of system peak demand (Figure 4-2). While participation increased dramatically over this five-year period, the value as established by the deficiency auctions of capacity has remained relatively steady, as illustrated by the stability of auction for New York's rest-of-state region (ROS) (
Figure 4-3).[15] The ROS is a more useful reference market because it excludes the NY City which had minimum prices set for auctions of capacity in that load pocket during most of that period. Moreover, about 75-85% of all SCR comes from ROS.

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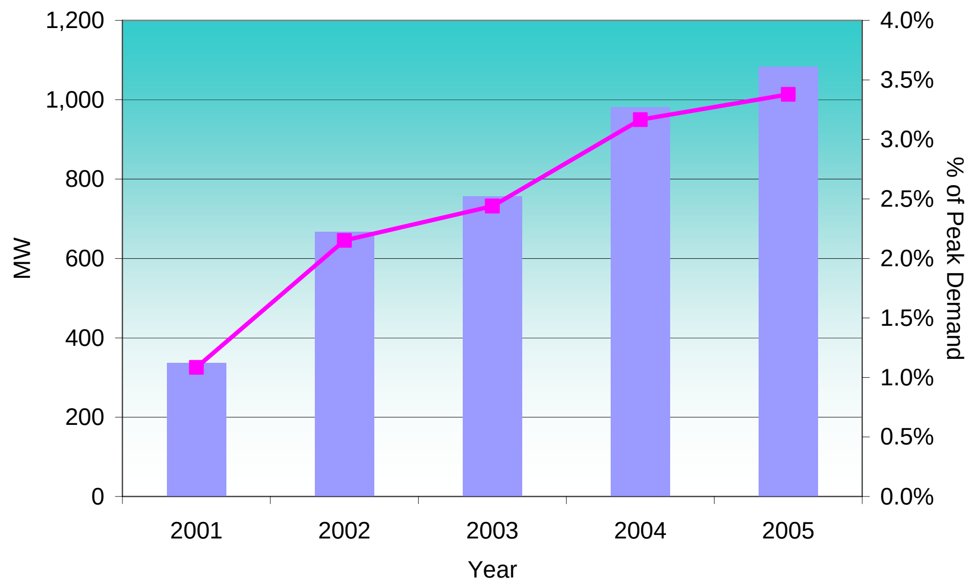
[15] Customers participating in the SCR program are provided with an up-front payment based on the value of their capacity as defined by the market, and are also given a guaranteed energy payment rate of $500/MWh) for performing during declared events. Failure to provide the contracted load reduction results in severe penalties that can, and often times do, leave a customer in an "under-water" position.

Figure 4-2 NYISO SCR Program Participation Levels by Year



What is striking about the supply curve implied in Figure 4-3 is that its slope is very flat. Relatively small increases in price are associated with the large increase in demand. If prices are not accounting for the dramatic increase in participation, other factors, like customer knowledge of the programs or a better understanding of the inherent risks associated with participation must be at work. In short, programs are only as successful as the marketing effort undertaken to sell them; demand response programs are no different. In the first year, there were only 17 entities offering to subscribe customers as SCR participants. As illustrated in Figure 4-4, that number had risen to 32 by 2005. In addition, the New York State Energy Research and Development Authority (NYSERDA) has provided a substantial amount of money to help defray the cost of installing interval meters (a requirement for program participation), enabling technologies (e.g. energy management control systems), and peak-load reduction efforts (e.g. energy efficiency). Furthermore, both the NYISO and New York State Public Service Commission (NYPSC) embarked upon an aggressive education and outreach campaign to boost enrollment in ISOsponsored demand response programs. All three combined to help bolster the supply of demand response resources willing to provide their load curtailment capability as a capacity resource.

Figure 4-3 NYISO Rest-of-State Capacity Auction-Clearing Prices (August Only)

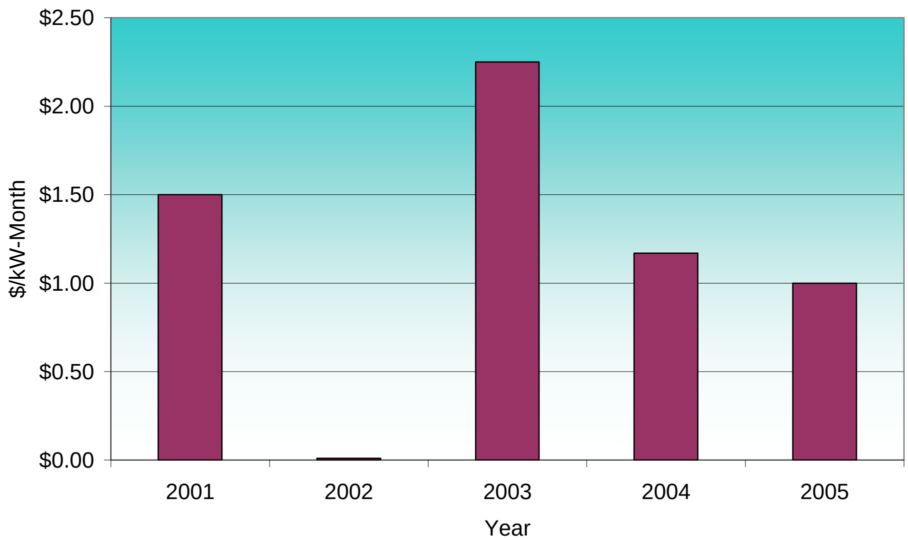
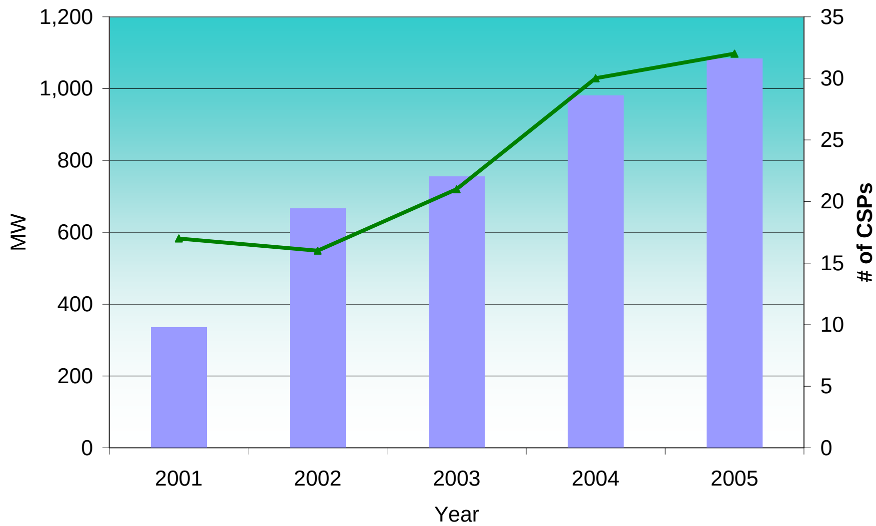
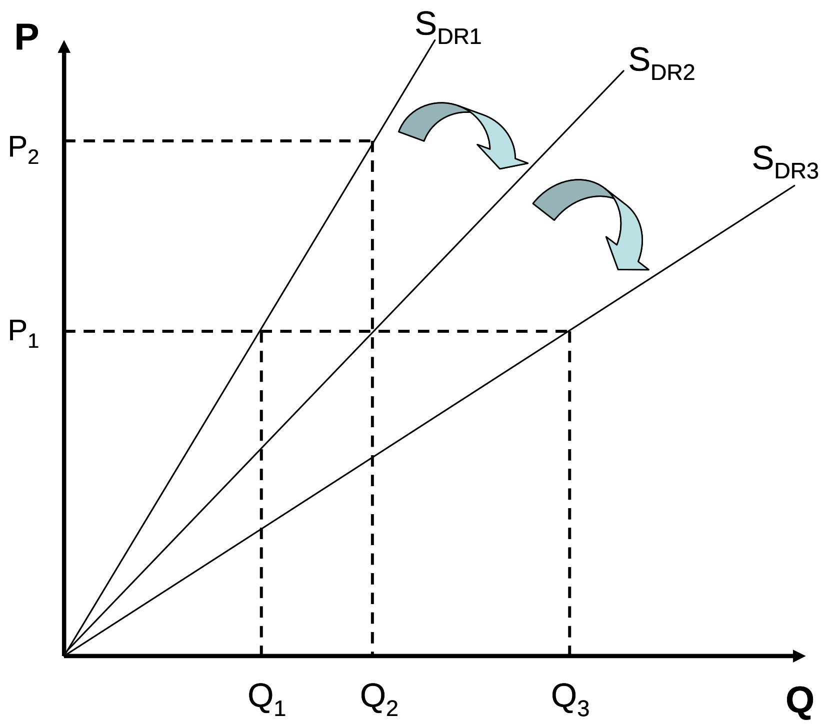


Figure 4-4 NYISO SCR Program Providers and Participation Levels by Year



Based on this experience, it would seem reasonable for KCP&L to expect a similar level of participation relative to its peak demand, 3.0 – 3.5%. However, as evidenced by the NYISO experience, this does not purely come about by paying customers a high up-front payment. Customers will supply more of, or more customers will supply, their load reduction capability as capacity if the payment rate is higher. However, as Figure 4-5 shows, the same level of demand response (Q_2) can be supplied at two prices: P_1 and P_2. In the former case, a lower marginal price is paid for the demand response because there are more customers willing to participate due to being better informed both about the program and as well as the tradeoff between its inherent risks and rewards. The higher price occurs because the pool of participants is smaller and the high price is the only way to attract the desired level of participation. With even more targeted marketing, it is possible to achieve the same level of participation with still a lower price, P_3, because even more customers are now willing to provide their load reductions as a capacity resource.

Figure 4-5 Supply of Demand Response as a Capacity Resource

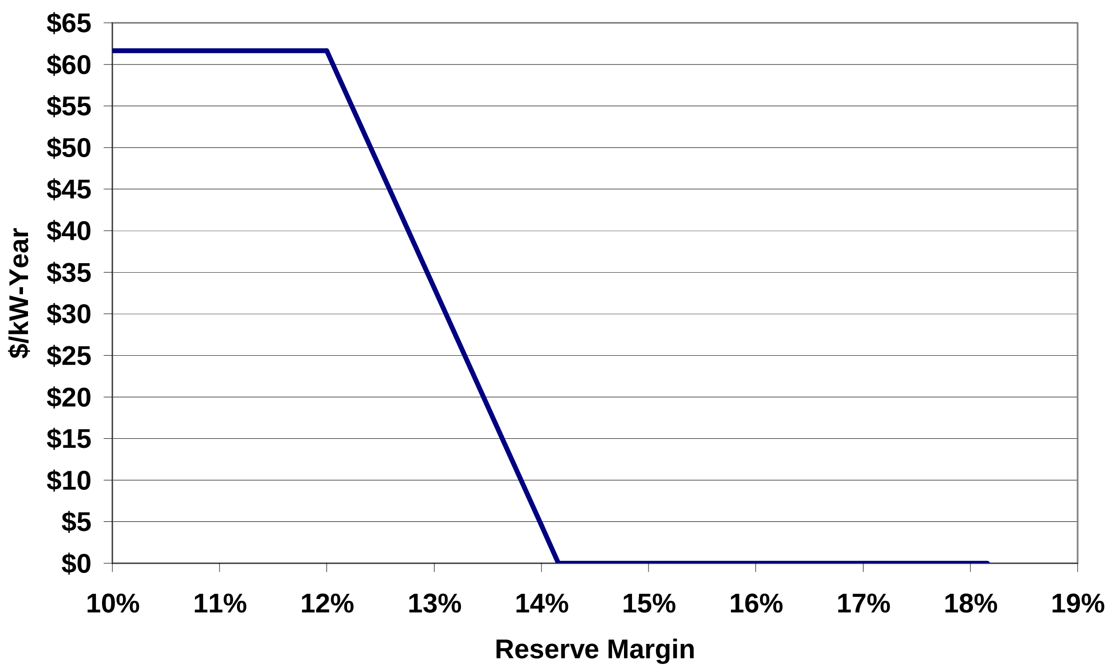


Targeting Demand Levels

The target level of demand response is not a static number. It changes as the reliability situation changes within the control area. As planning reserve margins get tighter, it is advantageous to have more customers serving as capacity suppliers. When there is excess capacity relative to what is required, less participation in these types of programs are required. Instead of arbitrarily limiting participation each year, a more efficient method would be to derive a relative value of capacity that is commensurate with the observed reserve margins in the system. Developing a "demand curve" for capacity is one way of doing this that has been instituted at several Northeastern ISOs (NYISO and PJM). Taking the New York ISOs most recent demand curve and applying it to KCP&L would produce a demand curve for capacity as illustrated in Figure 4-

6. Reading off the current reserve margin from the demand curve would produce the relative value of capacity. When reserves dip below the required 12% margin, the price offered to customers to be a capacity supplier would be no more than the cost to build a new combustion turbine.[16] At reserve levels that exceed the requirement, the value of capacity falls until having another MW of it is worth nothing, at roughly the 14% level. This mechanism allows KCP&L to pay customers what capacity is worth, while restricting participation through the most efficient means possible: price.

Figure 4-6 Demand Curve for Capacity

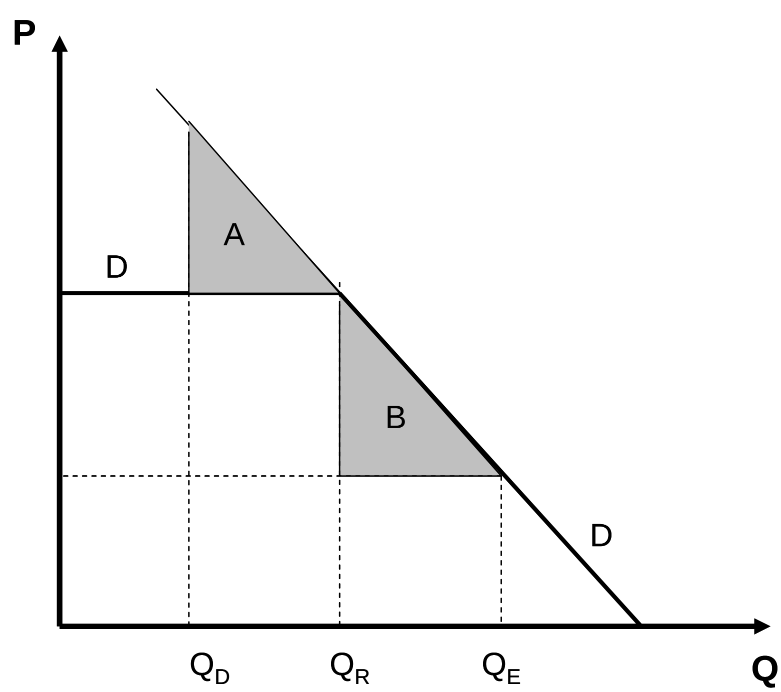


The increase in reliability associated with DR acting as a capacity resource can be quantified using welfare theory. The change in consumer surplus associated with the increase in reliability

[16] Randy Hughes of KCP&L provided this number, based upon his analysis.

is the benefit inuring to all customers. Figure 4-7 shows the ICAP demand curve and varying levels of capacity margins. At Q_D, the system is deficient of planning reserves resulting in an increase in the probability of an outage. If the demand curve, extended upwards in a linear fashion beyond the required reserve margin, Q_R, we would see the value of another MW of capacity is well-above the embedded cost of CT, representing the ceiling on the applicable demand curve. If enough DR is forthcoming to perfectly cover the shortfall in planning reserves, then society as a whole is made better off by the area A. This represents an increase in consumer surplus. If, however, capacity is in excess of the required reserve margin (Q_E), then having more of it will simply bring the probability of outage below planned levels, which still has benefits for consumers. At this level, consumers again receive an increase in consumer surplus associated with the increased level of reliability, but it is now equal to area B.

Figure 4-7 Welfare Benefits of Increased Reliability due to DR



Dispatch of Capacity Programs

Currently, KCP&L does not have fixed protocol for dispatching load curtailments. The Optimizer and MPOWER Plus programs provide provides resources that either replace or supplement capacity adequacy resources from conventional generation resources. To provide benefits, they must be dispatched so that system reliability is as good as or better than what would have resulted if these resources had not been contracted for. A standardized protocol assures that this will be the case, The KEMA team proposes that KCP&L protocols similar to those proposed by ISO-NE for loads selected to serve as resources in its Forward Capacity Market. The following statement summarizes those proposed protocols:

> "Demand Resource Seasonal Peak Hours" shall be defined as those hours in which the actual, Real-Time hourly load for Monday through Friday on non-holidays, during the months of June, July, August, December and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 System Peak Load Forecast, as determined by the ISO, for the applicable summer or winter season.
>
> ISO-NE reviewed the coincidence between high Real-Time hourly loads and OP-4 Action 6 (or higher) hours for the years 2001 through 2005 and found that a 90% threshold would produce at least one Seasonal Peak Hour for each day in which OP-4 Action 6 (or higher) was called, with the exception of 8/15/2003 (the day of the major Northeast blackout) and 10/25/2005 (a shoulder month). The frequency of missed OP-4 Action 6 (or higher) days and hours was greater at higher thresholds -- for example, a threshold of 95% missed nine days in which OP-4 Action 6 (or higher) was called.
>
> By definition, Demand Resource Critical Peak Hours include all OP-4 Action 6 (or higher) hours as well as hours in which the projected hourly load as shown in the ISO's most recent next day Forecast System Load for Monday through Friday on non-holidays, during the months of June, July, August, December and January is equal to or greater than 95% of the most recent 50/50 System Peak Load Forecast, as determined by the

ISO, for the applicable summer or winter season. The threshold can be higher because all OP-4 Action 6 (or higher) hours are included in Demand Resource Critical Peak Hours by definition.'[17]

In order to be effective, events must be called for on relatively short notice; two hours notice is required, but if conditions warrant, an event can be declared further in advance. The KEMA team recommends that KCP&L adopt protocols whereby when day-ahead forecast conditions are such that an event is likely, it issues an advance warning to participants in the capacity programs that an event might be called. Such issuance does not obligate KCP&L to declare an event the next day, and the issuance of an advanced warning is not a necessary condition for the declaration of an event. However, it will help KCP&L maintain a strong relationship with its customers.

4.2.2.2 Capacity Programs Offered

Table 4-5 below summarizes the program features. While our proposed demand response programs are based on existing programs, in the cases of MPOWER and VLR, the changes offered are, in our view, significant and will make MPOWER Plus a more marketable product.

[17] Explanation of protocols provided by H. Yoshimura, ISO-NE, November 10, 2006

Table 4-5 Capacity Program Features

KCPL Proposed Capacity Programs			
	Proposed MPOWER Plus	**Proposed VLR Plus**	**Proposed Optimizer**
Eligibility	Same as Existing MPower	**All C & I**	Small C & I Residential
Contract Term	**One Year**	One Year	Three Years
Metering	Hourly interval meter	Hourly interval meter	DLC equipment provided by KCPL
Peak Demand	N/A	**100 KW (aggregation permitted)**	N/A
Minimum Curtailable Demand	**100 KW**	**100 KW (aggregation permitted)**	None
Event Periods:	**Mandatory: All hours**	Voluntary: All Hours	**Mandatory: All Hours**
Event Season:	**Annual**	**Annual**	**Annual**
Event Advisory:	**Day-ahead as a courtesy only**	**Day-ahead as a courtesy only**	**Day-ahead as a courtesy only**
Event Notice:	**2 hours prior to beginning of the event**	**2 hours prior to beginning of the event AND Customer must opt in with estimated reduction amount prior to event start in order to qualify for event payment**	None
Event Duration:	**Minimum of 4 hours**	**Minimum of 4 hours**	Maximum of 4 hours
Event Frequency:	**Limited to once per day**	**Limited to once per day**	Limited to once per day
Event Limits:	**None**	**Limited to once per day**	Limited to once per day
Capacity payment:	**Established annually based on the value of resource adequacy capacity reserves**	None	None - Equipment provided by KCPL
Event energy curtailment payments:	**$0.50 per kWh of verified performance**	**$0.50 per kWh of verified performance**	None
CBL:	**Dynamic hourly value incorporates most recent historical load, with an adjustment for current weather conditions**	**Dynamic hourly value incorporates most recent historical load, with an adjustment for current weather conditions**	N/A
Event performance kWh:	**The difference between actual load during the event and the CBL by hour**	**The difference between actual load during the event and the CBL by hour**	N/A
Buy-through:	**None**	None	Limited to 1 per month
Non-performance penalty:	**150% of Capacity payment on difference between contracted kW and highest previous 12 months event kW curtailed** **Derating: average event performance over previous 12 months used to calculate subsequent year's maximum contracted capacity obligation**	None	Option to withdraw from program at no cost to customer Contract may be terminated on 90 days written notice

4.2.2.3 MPOWER Plus

Larger commercial and industrial customers are frequently willing to reduce usage during high cost periods or during times of system constraints, if they are compensated for their inconvenience. They may also be willing to reduce usage during critical periods for the greater good. MPOWER and its Special Contract rate equivalents are KCP&L's existing offerings. Customers receive an initial payment and a per event payment for load reductions and MPOWER currently has a penalty for non-obtainment.

While eliminating penalties will achieve higher participation rates in capacity programs their elimination reduces program effectiveness and raises the cost. Dispatchers must be confident on curtailment being undertaken at a predictable level. If there is no effective penalty for noncompliance, then at each event participants will compare the value of electricity to them, rather than to the consequences to the system if they fail to curtail, with the result that in most cases curtailments will be less than is socially optimal and practically needed.[18]

MPOWER Plus customers will receive an initial payment for subscribed load reductions and also receive a payment for kWh reduced during dispatched load reduction events. Substantial penalties for non-compliance are also proposed to ensure customers offering load curtailments to MPOWER Plus can abide by their contractual obligations to reduce consumption when called upon. Specifically, customers can be retroactively penalized to the beginning of the current contract period for failure to achieve the year the level of curtailment subscribed to the program for at least one hour during the prior twelve month period; this is known as the Deficiency Penalty. Partial performance during declared events will also reduce future program payments, in effect de-rating customers based upon observed compliance (e.g. Derating penalty). This way,

[18] Boisvert, R., Neenan, B. August 2003. Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets. Lawrence Berkeley National Laboratory Report No. LBNL-52530. Available at http://www.lbl.gov/

customers are provided a disincentive to overstate their capabilities both from a retroactive and going-forward standpoint.

Several modifications are proposed to the existing program to create the MPOWER Plus program (see Table 4-5). One of these is a change in the contract term to one year. As will be shown later, long-term contracts for this service do not take into account that the need for these resources differs depending upon generation adequacy. In some years, a sizable amount of customers should be subscribed to the program, while in others a minimal number of needed. In subsequent sections, it will be shown how to alter participation rates on an annual basis to more accurately reflect the need for such resources.

4.2.2.4 Optimizer

Energy Optimizer

Smaller customers may want to reduce their electricity costs but are unable to easily control their usage. They may also be unwilling to accept lower usage during most hours, but are willing to sacrifice for the greater good or for limited hours of the year. Direct load control programs, such as air conditioner and other major appliance cycling programs, offer customers the opportunity to accept usage limits during critical periods of supply constraint. KCP&L's Energy Optimizer program (rate tariff: ACC) is a sterling example of a well designed and marketed DCL program. The Optimizer program is available to residential and smaller commercial customers by tariff, but is primarily marketed to residential customers currently, until minor technology problems are resolved related to installing control equipment on some commercial customers' a/c units (resolution expected by the end of this year). The Optimizer program provides a programmable thermostat with which KCP&L can communicate and control can also be extended to electric water heaters and pool pumps. The customer can also program the thermostat via internet access. During control events, KCP&L can reduce customer consumption by activating controls on all connected appliances.

No major modifications are proposed for the Energy Optimizer program, though two areas of change are recommended: when control events are called and the up-front participation payment. Control events should be called on a consistent basis with the other demand response programs and value should be attributed to the Optimizer program consistent with other demand response programs. As with M-POWER Plus, the up-front payment provided to participants should reflect the exigent value of having these types of resources available to meet capacity reserve shortfalls. By making the payment rate variable, it is possible to more efficiently represent this value to participants, while not over-paying for the resource. More will be discussed about this topic later on.

4.2.2.5 VLR Plus

Many commercial and industrial customers are unwilling to reduce usage during high cost periods or for economic reasons, but are willing to reduce usage during critical periods for the greater good. The Voluntary Load Reduction (VLR) rider is KCP&L's emergency program that offers customers a per event payment for load reductions in times of great need. Subscribers also receive a small initial payment to develop a load reduction plan that outlines how that subscriber can comply with an emergency request for capacity (see Table 4-5). This program accommodates small-customer aggregation, where appropriate.

The VLR plus program provides KCP&L system dispatchers with another source of operating reserves. Its design follows that developed by NYISO and PJM where these resources are dispatched on two hour's notice when a shortfall in operating reserve is appears likely based on forecasted system conditions. The NYISO's version (called the Emergency Demand Response Program) pays customers $.50/kWh of load curtailed during curtailment events. Events are declared two or more hours before the start time and are of at least four hours in duration. NYISO dispatchers are given considerable latitude in determining when and for how long to declare an event to forestall the adverse consequences associated with prolonged reserve shortfalls.

In the case of NYISO, 1,800 MW of operating reserves are required to secure the system load (over 33,000 MW), divided evenly among the three categories: 10-minute spinning, 10-minute non-spinning and 30-minute non-spinning reserves. Currently, NYISO has almost 600 MW of load registered for its VLR program. Based on six years of experience (with enrolled loads ranging from under 200 to almost 600 MW), involving almost 100 event hours (periods when curtailment were requested), the average delivered MW is about 50% of that enrolled, which dispatchers take into account in forecasting when to declare an event, which triggers curtailments, and what the impact on load, and therefore on the level of operating reserves, will be. The experience-derated capability of the current 600 MW of VLR is therefore about 300 MW, about half of the level of any of the three categories of spinning reserves.

The KEMA team recommends that KCP&L enroll 100 MW of load in the VLR program, which corresponds to 50 MW applying a 50% derating factor. This provides supplemental operating reserves equal to 50% of the highest monthly operating reserve.[19] KCP&L is advised to examine its system dispatch practices and protocols to identify protocols that would define how these resources are to be utilized. If possible, KCP&L should prepare a description of these procedure and how they relate to system (e.g., peak demand) or regional (e.g., weather) conditions to provide potential participants with a frame of reference on when to expect such events and how often they might come about.[20]

The VLR program provides supplemental operating reserves to system dispatchers to resolve anticipated or actual reserve shortfalls. Protocols should be developed by KCP&L that provide guidance to when events should be declared. Because VLR resources are supplemental to available and generally sufficient (by SPP rules) operating reserves, and capacity resources

[19] Reserve requirements were described as being approximately 100 MW, 50% of which are spinning, in an email from KCP&L sent November 9, 2006.

[20] New York State Energy Development Authority prepares and distributes a brochure each year that describes the program and summarizes historic events,

provided by Optimizer and MPOWER Plus are substitutes for conventional capacity resources, VLC resources should be dispatched simultaneously with or after the capacity resources have been dispatched.

4.3 Programs Considered But Not Recommended

Two Programs were considered Critical Peak Pricing (CPP) and electronic bidding but were not recommend for the portfolio. Following is our reasoning behind this.

4.3.1 Critical Peak Pricing

We considered Critical Peak Pricing (CPP) because CPP has attracted considerable attention despite very limited experience with this design. CPP is a cross between the fixed diurnal rate schedule of TOU and the daily pricing of RTP. Typically, it has three pricing tiers: off-peak, on-peak and critical-peak where rates are substantially higher than on-peak rates. EDF in France uses color codes to designate which prices are applicable. Gulf Power has the first large scale application of CPP in the United States with over 6,000 residential subscribers. The recent California Statewide Pricing Pilot has also attracted attention on CCP because price response was twice as high under CPP as RTP.

The CPP rate design is premised on charging customers one rate, be it TOU or otherwise, for electricity consumption on "normal" days and replacing that rates or those rates with a substantially higher usage rate on selected days (CPP events) designed specifically to induce customer load reductions. The declaration of a critical peak event can be made for many different reasons: high forecasted energy prices, forecasts of setting a monthly or annual system peak, or reliability concerns. While on the surface the CPP may seem the perfect all-in-one rate, it, in fact, compromises the efficiency or reliability performance of plans designed to achieve a specific outcome.

Time-varying pricing programs, such as VPP and RTP will produce significantly more efficient results than CPP, since the marginal price charged for electricity, under those plans, more closely corresponds with the marginal supply costs. Since, CPP involves setting a super-peak price in advance with no relation to daily marginal prices, except by coincidence, it will almost always be above or below the actual marginal supply costs, thereby inducing inefficient consumption.

Alternatively, if the CPP program is intended and operated to reduce coincident system peak demand, it suffers a different sort of performance inefficiency because capacity needs are not highly correlated with high prices. Therefore, there are significant efficiency loses since the price charged for electricity in CPP is almost always out of sync with market value of capacity.

In the third case, where reliability may be jeopardized if load is not reduced, demand response programs that contract for curtailments and impose penalties for failure to comply are more effective ways to realize ensured curtailments than simply posting a pre-established price. To achieve equivalent results, the CPP price needs to be high enough to ensure curtailment by the entire load enrolled, but that can be accomplished only if all participating customers have identical price elasticities and loads. In all three cases, the portfolio of programs proposed by the KEMA team meets the needs served by CPP more efficiently and effectively.[21]

4.3.2 Electronic Bidding

All the northeast ISOs allow customers to bid curtailments as resources into the day-ahead energy market and some allow them to bid into real-time energy markets. Participation is very low, caused, in part, by customers not understanding the price discovery mechanism enough to want to take the risk. Moreover, customers already have opportunities to manage load by taking

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[21] For more on this see: Neenan, B. October 30, 2006. Direct Testimony of Bernard F. Neenan on behalf of Citizen's Utility Board. CUB-CITY Exhibit 3.0 Illinois Commerce Commission ICC Docket 06-0617; and Neenan, B. February 10, 2006. Prefiled Testimony of Bernard F. Neenan on Behalf of ISO New England, Inc. State of Connecticut, Department of Public Utility Control, Docket No. 05-10-03, Connecticut Power and Light Time-Of-Use, Interruptible Load Response and Seasonal Rates.

a default or competitive supplier RTP program service and by participating in ISO demand response programs. Since the proposed portfolio offer the same opportunities through VPP and RTP, the KEMA team sees no need to offer an additional bidding program that adds complexity with no additional value to customers or KCP&L. If SPP implements programs that allow for direct curtailment bidding, then, at that time, KCP&L may opt to act as the enabling agent for its customers that want to participate in the program.

5. Simulated Impacts – Price Response

As described in Section 4 the KEMA team developed a portfolio of price response programs, comprised of RTP, TOU and VPP in order to improve pricing efficiency in KCP&L's electricity market. Participation rates were established for each pricing plan based on the KEMA team's assessment using what has been achieved elsewhere, and the amount of price responsive load required to mitigate the most adverse consequence of price volatility.

In the stage of analysis covered in this section, simulations were run using the PriceFX model for each of the three MIDAS-based supply scenarios, referred to as the Low, Mid and High Market Outlooks to reflect forward market conditions and their consequential marginal supply cost to KCP&L. In each simulation, the price response was determined by how pricing plan participation rates, customer segment load profiles, and price elasticity levels, as specified in Section 2, were affected by the marginal supply costs in the Outlooks that constitute (to various degrees) usage prices in the three plans.

For each Outlook simulation, the model produced several categories of benefits for each of the five years in the simulation. The columns in **Error! Reference source not found.**Table 5-1 show various measures benefits that accrue to program participants and to all KCP&L customers over the five year period. Table 5-2 provides the annual level of benefits by category over the entire period 2007-2001, the detail of which are shown for the three different Market Outlooks of Low, Mid, and High in Table 5-3, Table 5-4, and Table 5-5 respectively. Table 5-6 provides a definition for each of the column headings in the benefits tables.

Benefits results are reported for each of the five years simulated in each Outlook. The benefits associated with any specific year of an Outlook reflect the specific prices produced by MIDAS, and, by themselves, are not particularly instructive, as they do not represent a prediction of that year so much as a contribution to a five-year period characterized by specific supply conditions.

Consequently, the following discussion compares the total, five-year benefits by category among the Outlooks to draw conclusions about the level and distribution of benefit of the proposed price response portfolio.

Participant Benefits

Participants in the pricing plans would pay more that they would under the reference rate if the pricing plans employ an unbundled design. Unbundled pricing refers to collecting customer and demand charges separately from the assessment of energy costs, and applying the pricing plan energy prices to all metered kWh consumption. Unbundled pricing assumes efficiency because usage prices can be tied directly to supply costs. In competitive markets, it is used to accommodate customer choice. However, in traditionally organized electricity market, like that of KCP&L, unbundled pricing efficiency comes at a high cost. Pricing plan participants would pay between $166 (Low Case) and $417 (High Case) million more Column 2 (Table 5-1). This results because the reference rate (the marginal rate for each KCP&L tariff) is low in comparison to the market value of electricity as defined by the MIDAS simulation.[22] Even after taking into account demand response behaviors, which involves shifting load from high to lower priced periods, participants would still substantially worse off. Customers are unlikely to participate in such programs on these terms.

[22] Reference prices were derived in Section 3 to reflect the marginal price customers are likely to see. We chose to model the default rates based on KCP&L's block rate structure. We expected the bulk of a customer's usage to be priced at the second block. In the simulations, all usage was billed according to this marginal rate to establish what participants would have paid for energy under their conventional tariff. Thus, the reference bill calculation does not comport exactly with what the bill would have been, but this mechanism provides an accurate representation of the nominal benefits of price response.

Table 5-1 Five-Year Price Response Portfolio Benefits ($ Million)

	Participants		Other Customers			Net Welfare Improvement
Market Outlook	Unbundled Pricing	Revenue Neutral Pricing	Cost Savings	Capacity Savings	Total	
Low	-166	3.9	19.0	6.9	25.9	0.5
Mid	-289	5.2	42.0	4.1	46.2	0.4
High	-417	6.9	69.2	5.9	75.0	0.5

If, however, the price-response plans were designed to be revenue neutral with respect to the default tariffs, the same level of price response would be undertaken resulting in customers realizing bill savings over the default rate. The revenue neutral participant benefits vary between $3.9 (Low Outlook) and $6.9 (High Outlook) million (Column 3, Table 5-1). These savings reflect the benefits of responding to high prices. In addition, the revenue neutral design affords customers opportunities to realize additional benefits from load growth at lower than tariff prices.

Revenue-neutral, two-part tariffs are both efficient and effective when the load-weighted marginal cost of serving customers is above the embedded average cost. Customer are unlikely to enrolling in a marginal cost-based rate that requires that they undertake substantial load modification just to reduce their bill to what is available under the average cost rate with no load changes and associated costs. The most successful RTP programs implemented by vertically integrated utilities utilized this structure for this reason, and report substantial price response.[23]

[23] *Barbose, G., Goldman, C., Neenan, B. December 2004. A Survey of Utility Experience with Real-Time Pricing. Lawrence Berkeley National Laboratory Report No. LBNL-54238. Available at http://www.lbl.gov/*

Revenue neutrality can be accomplished by establishing for participants a hedge whereby they agree to purchase a fixed level of usage (based on historic consumption patterns and levels) at the tariff rate and then all changes in usage from that level are priced at the pricing plan's marginal rate. KCP&L already employs such a mechanism in its RTP rate, employing a two-part structure that was designed specifically to make marginal cost pricing compatible with traditional, cost-based pricing of electricity. However, the current method of creating CBL a "blocked" CBL under which for each season, an average day with peak and off peak values is calculated from the customer's historic load data and that fixed load characterization comprises the daily CBL for all days of the season. All off-peak hours have the same CBL and all peak hours have the same CBL. We have found that with a blocking system that uses such wide blocks is that that for some customers, the deviation between the actual load and CBL can last for many hours, even when the customer is in fact operating normally and it deviates substantially in many hours that have high prices. Deviations from the CBL are treated as price responses, and settled accordingly. This results in a windfall gain. In those high priced hours where the averaged CBL is above the actual CBL, the customer appears to be responding but is not, and is paid the RTP price for doing so. Of course, in other hours the actual load is above the CBL, so the customer appears to be buying marginal power. But, if prices in those hours are close to the average tariff price, then the cost consequence is negligible, and the that customer uses the same load as is implied by the hourly CBL, but under the blocked CBL it is paid as though it curtailed load. This is a windfall. There are circumstances where such blocking can go against the customers, in effect penalizing the customer for participating in RTP. This is why Georgia Power and others that have adopted blocking options for customers limit them to choices where the averaging will no produce a windfall advantage. For example, new blocks would be calculated for each month, for a typical weekday and weekend day using four six-hour blocks or six four-hour blocks. We recommend that KCPL adopt such template blocks, and allow variations only after it has determined that doing so dos not favor the company or the customer. The principle has been adapted for time-of-use rates, as demonstrated by pilot programs at Public Service of Oklahoma and British Columbia Hydro (Barbose et al., 2004).

Other Customer Savings

All three Outlook simulations produce cost savings that accrue to other customers. Those savings are associated with from additional revenues generated by off-system sales and lower energy production cost collectively reported as cost savings in Column 4 of Table 5-1. In the Low Outlook, which assumes relatively low price volatility, those savings are $19 million. If price volatility is like that portrayed in the High Outlook, those savings are $69.25 million.

Reduction in coincident peak demand varies from year to year due to the difference in the level of avoided capacity costs that are used to value the savings. The assumed level of avoided capacity costs are: 2007=$43.74/kW-Year, 2008=$43.74, 2009=$42.09, 2010=$41.42, and 2011=$42.46.[24]

The resulting capacity savings (Column 5 Table 5-1) range from $6.9 in the Low Outlook to $5.8 in the High Outlook. This result appears to be counterintuitive, since the higher prices of the mid and High Outlook are expected to produce greater price response. The reason that coincident peak reductions are not increasing across the Outlooks is that the coincidence between the factors that result in the system peak load and marginal supply prices produced by MIDAS declines across the three Outlooks. Price response is driven by high prices, not peak loads. So, because High MIDAS price forecasts are characterized by the high prices occurring at times other than when the KCP&L system reaches to annual peak load, the coincident demand reduction attributable to price response is lower. This is not unusual. The NYISO and ISO-NE markets also exhibit relative low coincidence between peak loads and peak prices, especially in years when price volatility is the highest. Electric system are designed to have sufficient capacity to meet peak loads, so under most conditions, high loads are met with adequacy capacity and marginal supply costs are modest. High marginal supply costs often result from the confluence to high (but

[24] These numbers are taken from “Capacity Market Curve 033006.xls”, an evaluation of the annual levelized capacity only value provided by KCP&L.

not peak) loads and unit outages, which can occur during the spring or fall when loads are relative low, or on peak load season days but during hours when loads are not at their highest.

The change in Net Social Welfare (NSW) is relatively modest, around half a million dollars in all three Outlook simulations (Table 5-5 Column 7). This result comports with other studies of price response where price volatility is relatively low, at least compared to wholesale prices in California in 1999-2001 and the greater metropolitan New York City area during this past summer. However, reduced deadweight losses, which are what NSW improvement measure, are achievements whose importance is greater than the dollar measure would indicate because the more efficient utilization of resources in the electricity sector result sin increased efficiency in other sectors of the regional economy, which may be substantially larger.

The Implications for Staged Achievement of Equilibrium Pricing Plan Participation Levels

Because the proposed portfolio involves programs that are new to most customers, the steady-state participation rates for price response programs used in the analysis will likely not be realized immediately but accomplished gradually through the period 2007-2011.

Experience elsewhere indicates that a sustained and focused marketing effort is required to inform customers of the benefits, identify those that are the best candidates, and work with them to find the value associated with participation. Typically, the sales cycle on RTP is six months. The sales cycle for VPP recruitment is estimated to be from three to six months. TOU participation can be achieved effectively over a shorter sales cycle if a focused recruitment program is employed.[25]

The KEMA team believes that KCP&L can achieve these steady-state participation rates over the next five-years. The forecast ramp-up rates for each plan (TOU, RTP and VPP), is as follows;

[25] For example, both Public Service of Oklahoma and BC Hydro conducted 2-3 month enrollment initiatives to recruit customers to their revenue-neutral TOU pricing plans.

2007=10%, 2008=20%, 2009=40%, 2010=80%, and 2011=100%. The ramping up of participation over five years results in reduced benefits, compared to those associated with equilibrium participation levels for the first four years. Moreover, because price response programs are a contributor to meeting capacity retirements, the estimated contribution for the mature program participation must be adjusted to reflect the gradual ramp up of enrollment.

In section 4, participation (MW enrolled) goals were established for the Optimizer and MPOWER Plus programs in order to exactly offset the expected shortfall of capacity adequacy requirements projected by KCP&L over the next several years. These annual goals were adjusted to account for the coincident peak load reductions attributable to the price response programs, and revised to account for the ramp-up in price response program participations.

Table 5-2 provides the adjusted KCP&L System Benefits, coincident peak load reduction, and revised goals for capacity from the MPOWER Plus program. It is important to note that the benefits are not linear with respect to the ramp rate to full participation rates because they are defined by marginal costs which vary from year to year

Table 5-2 Benefits Comparison based on Participation Assumptions

	2007	2008	2009	2010	2011
Full Implementation					
Benefits	$25,565,129	$8,132,555	$7,831,879	$2,448,156	$2,202,061
Coincident Peak Reduction (MW)	25.1	16.0	16.9	16.7	20.9
Ramp-Up					
Ramp Rate	10%	20%	40%	80%	100%
Benefits	$4,221,379	$1,720,497	$3,567,828	$1,965,153	$2,202,061
Coincident Peak Reduction (MW)	2.5	3.2	10.3	13.4	20.9
Capacity Shortfall (MW)	49.3	66.6	91.9	0.0	0.0
DR Provided by Optimizer	15.0	15.0	15.0	15.0	15.0
DR Needed to Meet Capacity Req.	31.8	48.4	66.6	0.0	0.0

At the top of Table 5-2, the first two rows of values list the financial benefits and the corresponding coincident peak load reduction for 2007-2011 under equilibrium participation rates in the pricing plans that constitute the price response portfolio. The next two rows of Table 5-2 provide the equivalent values under the assumed ramp-up in participation over five years. The coincident peak load reductions are lower in every year but the last, when full equilibrium participation in the pricing plans is complete. The final three rows of Table 5-2 list the peak MW capacity shortfall in each year, as provided by KCP&L, the amount of DR expected from Optimizer, and the residual amount that is to be acquired through MPOWER Plus enrollments after adjusting for the pricing program ramp up. The lower contribution from the pricing program in 2007-2009 increases the requirement from the capacity program by approximately 22.6 MW in 2007, 12.8 MW in 2008 and 6.6 MW in 2009. Since there will be additional generation capacity and contributions from the pricing programs, we anticipate a surplus of capacity in 2010 and 2011 and, therefore, the shortfall is zero. The next section discusses the implications of surplus adequacy for the value of capacity provided by the Optimizer Plus and MPOWER Plus programs.

Summary

Simulations were conducted to identify the benefits associated with the implementation of a portfolio of price response programs by KCP&L beginning in 2007. The portfolio includes a TOU, VPP and RTP plans that link retail energy prices to marginal supply costs to various degrees. Three Market Outlooks were created to characterize the range of market conditions that could evolve over that period, and the corresponding marginal supply costs.

The simulations indicate that the benefits to participants are considerable, between 4 and 7 million dollars over the five-year period. But, this outcome realized only if KCP&L employs a revenue-neutral design. If the pricing plans apply their energy prices to all energy consumed, then participants would pay bills that are up to 40% more under these plans than they would the existing rates. This is because the projected marginal supply costs are above the energy rates in

KCP&L tariffs especially for the Mid and High Outlooks. RTP is especially punitive since its prices most closely track marginal supply costs.

Other customers, on the other hand, benefit from the price response of program participants in all Outlooks, ranging from $25.9 million (Low Outlook) to $75 (High Outlook) dollars over the five-year period. Clearing participation in price response programs and response to price changes by participants are in the interest of the collective KCP&L customer base. Accordingly, KCP&L can justify expending resources to induce customers top participate in the pricing plans and to assist them in preparing and executing price response behaviors. These benefits include savings associated with reduced peak coincident demand of 16-25 MW.

The first round of simulations portrayed the benefits associated with participation in the pricing plans at what was determined to be an equilibrium level, where the rate of participation in each plans can be expected to be stable but allowing for migration among the plans, which includes a conventional, fully price hedged tariff. However, achieving that level of participation will require time. To reflect staged enrollment, a ramp-up in participation (starting with 10% in 2007, and increasing to 20% in 2008, 40% in 2009, 80% in 2010 and 100% in 2011) was used in subsequent simulations to establish the associated level of participant and other customer savings, and the level of reduced coincident peak demand, which generally reflect the ramp up rate in participation.

Table 5-3. Estimated Benefits from Price response Programs – Low Case

	Customer Energy Bill					KCPL System Gross Benefits					
Year	Default Tariff	Participation w/o DR	Participation w/ DR	**Total Participant Savings**	**Total Demand Response Savings**	Off-System Sales	Reduced Bilateral Cost	Reduction in Coinc. Peak (MW)	Deferred Capacity Costs	**Total Benefits**	Change in NSW
2007	$670,560,544	$656,355,599	$656,111,015	**$14,449,529**	**$244,584**	-$52,126	$1,539,863	15	$637,270	**$2,125,006**	$34,405
2008	$604,108,907	$653,315,306	$652,986,740	**-$48,877,832**	**$328,566**	$101,594	$1,435,591	31	$1,366,751	**$2,903,937**	$30,372
2009	$563,134,289	$608,661,842	$608,091,193	**-$44,956,905**	**$570,649**	$191,249	$3,536,406	32	$1,366,924	**$5,094,579**	$88,498
2010	$518,403,126	$559,288,485	$557,442,412	**-$39,039,286**	**$1,846,073**	$980,497	$9,477,237	39	$1,626,323	**$12,084,057**	$196,437
2011	$609,676,969	$658,553,748	$657,619,253	**-$47,942,284**	**$934,495**	$326,180	$1,504,516	45	$1,910,573	**$3,741,269**	$177,594
Total	$2,965,883,834	$3,136,174,979	$3,132,250,613	**-$166,366,779**	**$3,924,367**	$1,547,394	$17,493,613	45	$6,907,841	**$25,948,848**	$527,306

Table 5-4. Estimated Benefits from Price response Programs – Mid Case

	Customer Energy Bill					KCPL System Gross Benefits					
Year	Default Tariff	Participation w/o DR	Participation w/ DR	**Total Participant Savings**	**Total Demand Response Savings**	Off-System Sales	Reduced Bilateral Cost	Reduction in Coinc. Peak (MW)	Deferred Capacity Costs	**Total Benefits**	Change in NSW
2007	$670,560,544	$715,983,586	$714,189,793	**-$43,629,249**	**$1,793,793**	$847,383	$23,618,103	25	$1,099,644	**$25,565,129**	-$36,373
2008	$859,087,405	$928,071,715	$926,800,625	**-$67,713,220**	**$1,271,090**	$505,334	$6,928,760	16	$698,461	**$8,132,555**	$174,204
2009	$755,480,179	$817,351,820	$816,513,812	**-$61,033,634**	**$838,008**	$291,774	$6,830,154	17	$709,951	**$7,831,879**	$123,108
2010	$844,004,426	$912,966,273	$912,260,459	**-$68,256,033**	**$705,815**	$292,628	$1,461,682	17	$693,846	**$2,448,156**	$54,867
2011	$601,014,108	$650,250,698	$649,583,603	**-$48,569,495**	**$667,095**	$215,800	$1,098,543	21	$887,719	**$2,202,061**	$122,256
Total	$3,730,146,661	$4,024,624,092	$4,019,348,292	**-$289,201,631**	**$5,275,800**	$2,152,919	$39,937,241	25	$4,089,621	**$46,179,780**	$438,061

Table 5-5. Estimated Benefits from Price response Programs – High Case

	Customer Energy Bill					KCPL System Gross Benefits					
Year	Default Tariff	Participation w/o DR	Participation w/ DR	**Total Participant Savings**	**Total Demand Response Savings**	Off-System Sales	Reduced Bilateral Cost	Reduction in Coinc. Peak (MW)	Deferred Capacity Costs	**Total Benefits**	Change in NSW
2007	$670,560,544	$802,287,634	$800,532,863	**-$129,972,319**	**$1,754,772**	$947,674	$17,193,914	52	$2,279,221	**$20,420,809**	$16,480
2008	$1,478,839,941	$1,596,831,160	$1,594,988,929	**-$116,148,988**	**$1,842,231**	$541,908	$24,854,220	13	$584,624	**$25,980,752**	$172,064
2009	$1,068,700,031	$1,155,661,494	$1,154,693,700	**-$85,993,670**	**$967,793**	$267,031	$9,871,494	26	$1,093,570	**$11,232,094**	$119,322
2010	$672,452,831	$724,380,035	$722,211,454	**-$49,758,624**	**$2,168,581**	$1,114,055	$14,081,077	28	$1,150,554	**$16,345,686**	$209,137
2011	$434,925,012	$470,303,406	$470,155,637	**-$35,230,626**	**$147,769**	$13,216	$305,388	17	$742,864	**$1,061,468**	$23,467
Total	$4,325,478,358	$4,749,463,729	$4,742,582,584	**-$417,104,226**	**$6,881,146**	$2,883,883	$66,306,093	52	$5,850,832	**$75,040,808**	$540,470

Table 5-6 Key to Simulation Benefits Tables

Customer Energy Bill

Column 1. Year. Simulation year.

Column 2. Default Tariff. The revenue from energy sales from pricing plan participants if they had stayed on the reference tariff. The default revenue for 2007 is established by pricing all load at the reference marginal rate. Thereafter, the reference rate is adjusted in proportion of the change in RTP prices, to maintain parity between the two bill amounts without price response.

Column 3. Participant cost w/o DR. What participants on the pricing plans would pay if they did not respond to prices at all, and used the same load they would have under the reference rate

Column 4. Participant cost w DR. Energy cost to participants assuming that they exhibit the specified level of price response.

Column 5. Participant Unhedged Savings - The difference between what they pay as price responsive participants and what they would pay under the reference tariff.

Column 6. Participant Hedges Savings – savings if participants are given a revenue-neutral guarantee

KCP&L System Benefits

Column 7. Off-System Sales – Change in KCP&L sales resulting from load changes by participants. In any hour that a participant in nay pricing plan reduces it usage, KCP&L is assumed to sell that energy at the prevailing RTP price. In any hour that a participant increases its usage, which can be load shifted from a higher priced period or load growth, KCP&L is assumed to have reduced sales revenues valued at the RRTP prices.

Column 8. Reduced Bi-lateral Costs.

Column 9. Coincident Peak Reduction. Reduction in the system coincident peak associated with price response.

Column 10. Deferred Capacity Costs. The reduced peak demand priced at the prevailing avoided capacity cost.

Column 11. Total Benefits. The sum of the four system benefits category values

Column 12. Change in NSW. The increase in Net Social Welfare associated with price response.

6. Supply of Regulatory Capacity

Based on documents provided by KCP&L, the utility must maintain a 12% capacity margin. This adequacy requirement is designed to ensure that system reliability can be maintained under contingent conditions characterized by the loss of one or more generation units.

Demand response can contribute to meeting that requirement at least cost, and provide supplemental reserves that provide benefits to all customers. To accomplish that, programs that induce customer to reduce loads must set the incentive or prices paid for such curtailments to reflect the value in increased reliability.

The KEMA team proposes that KCP&L offer three capacity programs that are revisions to programs currently available, and therefore, the proposed programs have the same names, with a Plus suffix to distinguish design modifications. Participation goals for these programs are derived based on the value they are expected to deliver.

6.1 VLR Plus

The VLR Plus program is intended to provide KCP&L system dispatchers with resources that supplement operating reserves available from generation units. These resources would be dispatched, by declaring a VLR program event, during times when sustained operating reserve shortfalls are anticipated. The operative term is anticipated, since participants must be given two hour's notice of the start of a VLR event. Their value, though, is in contributing in the restoration of operating reserves, or the decreased necessity for converting operating reserves to energy to meet load. By helping to maintain required operating reserve levels, the probability of an outage should be decreased, all other things being equal.

A review of the protocols adopted for "emergency" demand response programs elsewhere provides a framework for the design or KCP&L's program. The creation of centrally organized markets with a single entity, the Independent System Operator (ISO), focused attention on the role and value of loads acting as capacity resources. FERC ordered the northeast ISOs (NYISO, ISO-NE and PJM) to implement programs explicitly to take advantage of load curtailments available from customers who are willing to curtail their usage when instructed to do so by the ISO. Because curtailable loads were considered by the ISO as resources (or "assets" in ISO-NE's parlance), their utilization and compensation was determined by stakeholders, that included generation interests, load-serving entities (LSE), and those representing customer interests. While there was general agreement that such resources could be valuable, the ISO operating procedures required that the valuation be made explicit, and it had to be acceptable to a majority of stakeholders to be implemented.[26]

Through a process of independent inquiry and research supported by collaborative processes, the northeast ISOs established specific protocols for when demand response resources are required to, or asked to, curtail, and corresponding resource valuations were developed.. The salient aspects are as follows:

- All three ISOs distinguish between capacity resources and emergency resources. Capacity resources replace an equivalent amount of generation in the fulfillment of an LSE's capacity requirement, which varies for 116 to 118% of its estimated peak load.
- The capacity value is determined by the capacity markets. Customers sell their certified capacity equivalent directly to an LES or through capacity auctions administered by the ISOs. The capacity value is determined by market forces, not administrative procedures and processes as is the case with avoided costs. Failure to comply with a curtailment event results in the imposition of penalties equivalent to those that would be assessed a

[26] The ISO Board is empowered to file with FERC for approval of tariffs even if its membership does not approve of them. In some instances, PJM demand response programs were implemented under those circumstances.

generation unit that failed to meet its ICAP requirements. This is consistent with the philosophy: equal pay for equal performance.

- In order to get credit for it from its reliability council ISO-NE is required to treat its demand response resources as 30-minute non-spinning reserves. As a result, unlike their PJM and NYISO counterparts, customers participating in the ISO-NE capacity program must install metering and communication equipment that allows the ISO to monitor its load in near real-time.
- In addition to capacity payments, participants that curtail during events are paid for the energy they provide, just as a generation unit assigned to provide reserves is paid under reserve pickup that results in its providing energy to the system.
- Emergency programs administered by PJM and NYISO established payments from loads voluntarily curtailed during events to reflect the value of lost load (VOLL). Participants that curtail are paid the higher of $500/MWh of load curtailed or the prevailing real-time locational marginal prices (LMP).
- NYISO and ISO-NE conduct annual studies to ascertain, if, in fact, when events are called, that the realized value of these curtailments was at least as high as the payment made employing a VOLL methodology.

The protocols and associated values developed within these markets provide a foundation for establishing the value of demand response for programs administered by KCP&L. SPP is in an early stage and has not yet adopted procedures for integrating demand response into its market operations. However, its final structure will likely have some elements in common with existing ISOs, among them the establishment of operating protocols, which create a means for establishing the system-level value of demand responses. Inevitably, this transparent valuation will influence what a utility can pay customers for loads acting as resources that are dispatched by SPP, or at least under protocols it establishes. The KEMA team has anticipated how demand response will be integrated into SPP operation and valued, so that it can design programs for

KCP&L that anticipate those requirements and contain provisions that allow for the migration to them as conditions warrant.

Emergency program participation goals proposed by the KEMA team are predicted on KCP&L's required level of operating reserves, which is roughly 100 MW.[27] In ERCOT, demand response is not allowed to provide more than 50% of the Responsive Reserves requirement. The New York ISO's (NYISO) Emergency Demand Response Program (EDRP) currently shows 554 MWs enrolled in the program, of which roughly 42% is expected to respond during declared events (Neenan Associates, 2004). This corresponds to emergency resources equal to about 50% of the 30-minute reserve requirement of 600 MW. The KEMA team recommends that the VLC target goal for participation be set at 50% of KCP&L's system operating reserve requirements seems achievable, about 50 MW of available capacity, which requires about 100 MW of enrolled in the long-run, and would provide a level of additional reliability commensurate with that provided by these programs in other control areas.

6.2 MPOWER Plus

The MPOWER Plus program provides value to KCP&L by having demand response resources to supplement generation capacity resources. As stated previously, the best way to get the optimal number of capacity resources is to provide the correct incentive (price) that reflects the existing value of capacity. .

KCP&L's existing MPOWER program provides customers with an up-front payment in return for the obligation to curtail when called upon to do so. The program currently has three customers, who have pledged roughly 4 MW for a payment of $16/kw-year. KCP&L has asked:

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[27] KCP&L Control Area is obligated to procure a percentage of the SPP operating reserve requirement, which changes on a monthly basis. The level of operating reserves range between 70 MW to 105 MW, depending upon exigent system circumstances. We chose a number on the high side of the distribution, but not the overall maximum, to illustrate the level of participation that would be desirable.

what are the implications for achieving higher participation rates? Will the incentive have to be raised, and if so by how much? Is there are deterministic relationship between the incentive offered and the amount enrolled in such a program, or are the other random, and therefore uncontrollable factors at play that cause customers to demand different incentives from year to year?

These questions can be addresses by characterizing the supply curve for load curtailments under KCP&L's MPOWER program. That supply curve indicates the level of load reduction (MW) customers would provide at given incentive prices, defined as the $/kW-year payment of load committed to the program. Naturally, the curve is upward sloping, the higher the price the greater the level of participation, and emanates from the origin. What needs to be determined is the slope of this curve and whether it is linear, or non-linear, the latter indicating that the marginal cost of higher level to participation is increasing.

The supply curve for load curtailment under a program like MPOWER can be derived from actual experience in KCP&L's market, from experience with similar program elsewhere, or both. Consider the KCP&L experience to date. Using the limited experience to date (one year of recruitment), the resulting MPOWER supply curve would look like that portrayed by the solid curve labeled MPOWER in Figure 6-1. The supply curve is defined by extending a straight line from the origin through the observed transaction (4 MW at $16).[28] The result is that doubling the payment rate from that paid last year (from $16 to $32/MW subscribed) would double the amount of enrolled load reduction to 12 MW. By extension, under this supply characterization,

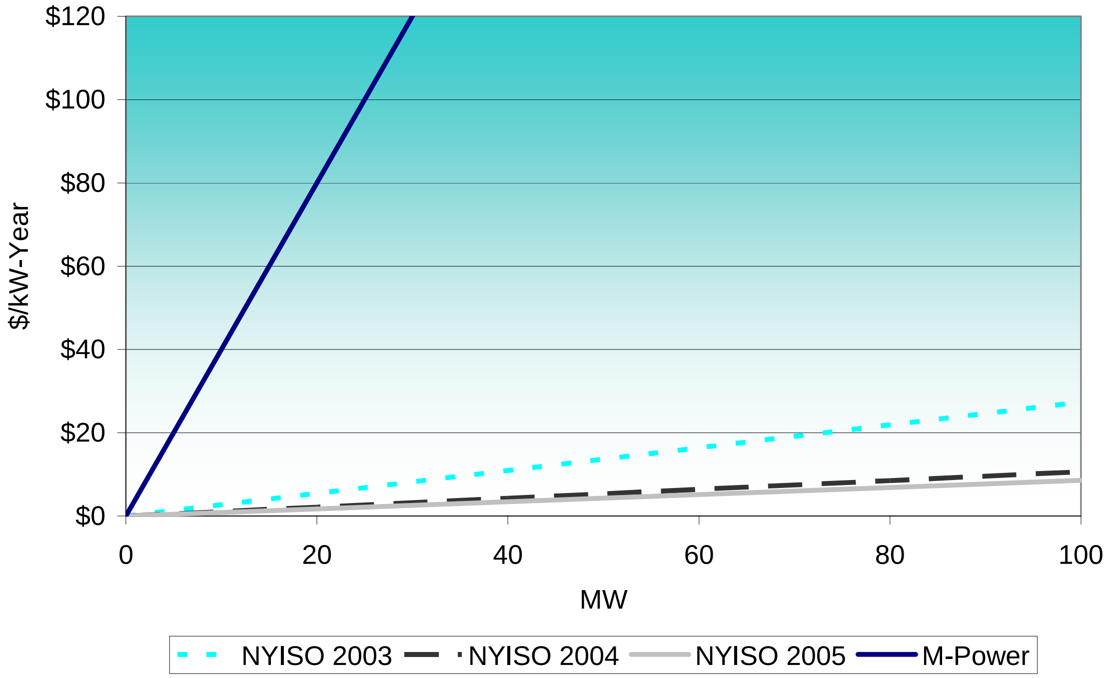
[28] This supply curve was developed using the most recent experience in the M-POWER program. Clearly, if data from other years were available, the supply curve may have differed dramatically. However, KCP&L previously used the PLCC program to contract for curtailable loads, which utilized a different design. The exact point in space where the M-POWER supply curve resides now is unknown. But, the initial experience suggests that it deviates dramatically from those observed in markets where DR has been marketed vigorously to serve as a capacity resource. The analysis provided herein is intended to show the tradeoff between payment and marketing dollars in an illustrative manner, not a definitive one. It may turn out that as a result of the PLCC experience, the market exhibits more maturity than M-Power indicates. The best way to find out is to launch a well-orchestrated enrollment campaign and evaluate its outcome closely

only about 18 MW of participation would be achieved at incentive rate equal to KCP&L's avoided cost of about $60/kw-year. Achieving enrollment of 50 MW, which is what is required to fill the expected capacity shortfall in 2007-2009, would require paying over $300/MW-year, over three times the value of capacity as defined by KCP&L's avoided costs.

Programs like the NYISO's Special Case Resources (SCR) program discussed earlier, after which the MPOWER Plus program is designed, provide a compelling means to characterize the supply of MPOWER capacity resources. The SCR program has been in operation since 2000, so the revealed supply of capacity through load curtailments represents a considerable degree of maturity, and therefore presages what can be expected form KCP&L's customers after similar experience.

A series of supply curves were created from the last three years of NYISO SCR experience were constructed and superimposed over that derived from the one-year experience with MPOWER, as illustrated in Figure 6-1. These supply characterizations suggest that the KCP&L MPOWER capacity program enrollments might be realized at prices significantly below the avoided cost when the market reaches a similar level of maturity.

Figure 6-1 DR Capacity Supply Curve



The dramatic difference between the MPOWER supply curves and the NYISO supply curves is in large part due to how market maturity influence customers' inclination to participate. A mature markets for load curtailments is characterize by a widely proliferated and high degree of knowledge by customers of costs they can expect to incur to fulfill their enrollment obligation. The incentive is obvious and definitive. However, the benefits of participation are not. Curtailing on demand involves costs. Customers that have no experience with having to reduce loads on short notice do not have any frame of reference with which to ascertain just what that involves and what the cost of doing so are. Some customers discover only at the first curtailment that processes that they though could be curtailed without affecting other more vital (and therefore not so discretionary) ones are subject to interdependencies. Lacking experience, customer may not correctly anticipate the coincidence of key electricity usage with the times of day when curtailment are called. These are among the reasons for the high level of turnover in emergency and capacity programs like that of NYISO, especially in the early years of implementation where the level of discovery is high but experience is low.

Moreover, a new program like MPOWER that ties curtailment events to market circumstances that customers are not familiar with further complicates estimating the net benefits of participation, especially when penalties are levied for non-compliance, which adds substantially to the cost or participation. Most customers can envision circumstances whereby exigent economic or other circumstances make curtailing in infeasible. Until there is sufficient program experience to reveal the likelihood and nature of curtailments, as is the case in New York, customer will likely err on the side of assuming that curtailments are more likely than current condition would dictate as a reasonable expectation, or perform their calculations based on the tails of the distribution, because they are risk averse. Either decision results in high expected cost of participation that reduce expected net benefits and for many are negative.

As discussed in Section 1, the promotional initiative for MPOWER was limited. By comparison, the NYISO program was heavily promoted by utilities, competitive retailers and entities called curtailment service providers that specialized in finding customers to participate in SCR. The latter employed a shared-saving approach to get customer to enroll. In addition, the NYISO aggressively promoted and educated consumers about the program. The NYSERDA also prepared and distributed promotional materials, subsidized metering costs, and made availability of funds to purchase enabling technologies helped further bolster enrollment. Collectively these efforts resulted in the wide-spread dissemination of information about participation costs and benefits, which helped customers, estimate the expected benefits of participation. As a result, the supply curves for NYISO (Figure 6-1) are considerably more flat, and indicate that KCP&L's goals can be achieved substantially lower payment rates

Revised Capacity Program Goals

As previously discussed, KCP&L staff predicts native generation capacity shortfalls for the next three years, until the Iatan generation station comes on-line in 2010. The reserve deficiency ranges between 49 and 92 MW. However, this deficiency is reduced by coincident peak load reductions undertaken by customers on price-responsive retail rates. So the adjusted capacity shortfall, as shown in Figure 6-1, becomes the capacity programs' enrollment goals

The policy directive is that if customer value reserves that are greater than those than NERC reliability protocols require, then KCP&L is justified in procuring demand response program participation even when reserves associated with installed generation are adequate to meet the requirement, or even exceed it. However, paying the full avoided cost is not justified, since the value of another MW of capacity reserves moves the system even further past capacity adequacy levels. Having more reliability is always preferred to less, but that value is not constant, but rather it is downward sloping. The higher the level of reliability, the less an additional MW of capacity is worth. This relationship is explicitly codified by creating a capacity demand curve, which represents the value for every level of reliability, both in excess or deficient of required reserve margins. By using the demand curve (as represented in Section 4, in Figure 4-6), the value of capacity in deficient years would be the carrying cost of a CT ($61.65/kW-Year). Given the current MPOWER Plus supply curve, such a payment rate would only have elicited 15 MW of demand response, significantly less than would be required to fill the deficit. However, in years when there is a plethora of capacity, the demand curve is also useful in determining the value of additional reliability. The KEMA team recommends that KCP&L explore with its regulators the benefits of specifying a reliability demand curve to guide pricing and enrollment of capacity-based demand response resources.

What Should KCP&L Pay for MPOWER Plus Participation?

Table 6-1 compares the cost of acquiring the capacity goal for MPOWER (before netting out the contribution of the Optimizer program) uses the KCP&L experience MPOWER supply curve (the first three rows of Table 6-1) and the cost using the mature NYSIO capacity supply curve (the bottom three rows of Table 6-1). The capacity requirement from MPOWER to make up for projected adequacy shortfalls derived earlier are 31.8 MW in 2007, 48.4 MW in 2008, 66.6 in 2009. Adequacy is in a surplus state in 2010 and 2011. The consumer surplus values reflect the benefits to all customers of closing the shortfall between available and required capacity; it is zero in 2010 and 2011 because there is a surplus of adequacy capacity.[29]

Table 6-1 MPOWER Participation and Benefits by Year

	2007	2008	2009	2010	2011
MPOWER Plus					
Price to Cover Shortfall ($/kW-Year)	$127.30	$193.59	$266.55	$0.00	$0.00
Cost to Procure Shortfall kW	$5,961,204	$12,272,608	$21,760,819	$0	$0
Consumer Surplus	$801,899	$1,447,550	$2,563,096	$0	$0
Mature NYISO					
Price to Cover Shortfall ($/kW-Year)	$2.73	$4.15	$5.72	$0.00	$0.00
Cost to Procure Shortfall kW	$127,916	$263,346	$466,944	$0	$0
Consumer Surplus	$801,899	$1,447,550	$2,563,096	$0	$0

Meeting the 2007 goal assuming the MPOWER supply curve requires paying $127.30/kW-Year for that year, almost three times the avoided cost for a total expenditure of $5,961,204 (Table 6-1). If the mature supply curve characterizes existing market circumstances, then the cost in 2007 would be $2.73/kW-Year. The discrepancy is larger still in 2008 and 2009.

[29] Consumer surplus is derived by using the derived demand curve, and projecting it upwards when reserves are deficient. The area under the demand curve between the price at the required level of reserves and the price at the existing capacity margin.

The current supply curve for curtailable load under MPOWER probably lies somewhere between these two extremes. However the actual character can only be discovered through sustained and effective promotional campaigns to inform customers of the gross benefits of participation (the payment they will receive) and help them reduce the uncertainty of the expected net benefits of participation. The reduced cost to meet the goals represents a guideline to what can be paid to reveal the true supply curve. For example, if KCP&L believes that the NYISO curve is the actual curve, then it can spend up to the sum of the difference in the cost in Table 6-1 to achieve that supply relationship. The question that follows is: how much can be spent?

The KEMA team believes that for the period 2007-2009, the supply of capacity curve lies between these extremes. Its exact slope however is unobserved. Based on the NY experience, marketing and promotion expenditures can substitute for incentive payments. But, since that expenditure has not been reported, the total amount is unknown, so a tradeoff function can not be explicitly derived. The KEMA team is not aware of any research that would inform this question. Aggregating experience for several jurisdictions is also not productive, because there are too many design and circumstance variations that can not be accounted for.

The KEMA team recommends that KCP&L develop a comprehensive set of promotional and informational programs, to a wide range of commercial and industrial customer, immediately to start the dissemination process needed to build awareness of the program as a prelude to the start of the spring promotional campaign which has a goal of 50 MW of capacity equivalence from MPOWER (adjusted to the level of Optimizer capacity available this summer). KCP&L should offer participants 75% of avoided cost in cash incentive for 2007 (about $45/kW) for a one year contract. This value roughly corresponds to the Capacity-Only cost for a CT as shown in Section 3 Table 3-3. It can then offer the difference between as reimbursement for cost incurred by the customer to conduct a curtailment capability audit, and control for information technology or other services that would increase the ability to meet curtailment obligations. This should be accompanied by research to better characterize the nature of the supply curve by customer segment so that next year the incentive more accurately reflects the underlying supply and thereby maximizes the benefits all customer realize.

Table 6-1 indicates that no contribution from M-Power is required in 2010 and 2011, because available generation not only meets, but exceeds the adequacy requirement. However, KCP&L should consider continuing M-Power into 2010 and 2011 because, experience in other markets has shown, that the transaction costs of rebuilding a program such as this will be significantly higher if the program is not continued because of a the additional generation capacity. In our view, continuation should be valued much as an organization values insurance.

The value of capacity other than an amount exactly equal to avoided cost is measured by consumer surplus, and described in Section 4. In Table 6-1, the consumer surplus associated with M-Power grows from $0.8 million in 2007 to $2.5 million in 2009; this is the value of making up for the shortfall in adequacy reserves using a demand curve for capacity like that adopted by NYISO. Adequacy capacity in excess of KCP&L's required amount have value, but in is less than the avoided costs, and the marginal value declines as the amount supplied increases, eventually reaching zero at about 14% adequacy reserve margin.

By using the demand curve (as represented in Section 4, in Figure 4-6), additional capacity is worth no more than $4.57/kW-Year, since that is the marginal value of the additional capacity supplied by generation. That means that KCP&L should pay M-Power participants no more than that amount in 2010. In 2011, the surplus from generation is enough to drive the marginal value of additional capacity to zero, so M-Power has no incremental value, at least according to this demand for adequacy representation. If there is no value to M-Power resources, what is the value of the already contracted for 15 MW of Optimizer resources? They also are superfluous and therefore provide no additional value to consumers under this valuation regime.

This result highlights the challenge in forward contracting for demand responses resources, or that matter any capacity resource, very far into the future. The determination of what to pay must take into account system conditions that vary from year to year, and assess the value accordingly. As long as the present value of the payment is adjusted for these variations, then the forward contract can be rationalized. It also points out the value of employing a more fungible design that adjusts the amount paid for curtailable load each year to reflect exigent circumstances. The recommended KCP&L portfolio of capacity-providing programs includes both types, forward and yearly contracting, which provides KCP&L with diversity in the face of uncertainty.

Contract Term

Our proposed plan for MPOWER has a one year contract term. KCP&L currently offers one, three and five year options for contract term for MPOWER. We understand that KCP&L does so to reduce the recruitment transaction costs and to gain longer term reliability. While we understand the logic behind that position, the KEMA team believes that a one-year contract terms is preferable for two reasons. The first reason is that customers are not likely to accept such and offer and this would be an inhibition to marketing. A survey conducted in 2003[30] showed that very few customers were inclined to sigh up for more than six months at a time. This is attributable to the highly volatile nature of market prices for capacity in competitive environments. KCPL can use the forward curve for capacity to create a levelized annual payment that is offered to customers that contract for more than a year. Secondly, under today's forward view, a levelized five-year contract would underpay relative to exposure in 2007-2009 and overpay relative to exposure in 2010 and 2011. Such a contract could include an additional payment equal to the transaction costs savings associated with not having to market for new subscriptions, but that savings is likely to be relatively small. Should KCP&L decide to maintain the multi-year contract options, KEMA recommends that such contracts include explicit

[30] Meehan, G., LaCasse, C., Kalmus, P., Neenan, B. February 2003. Central Resource Adequacy Markets for PJM, NYSIO and NE-ISO. Final Report.

termination clauses so that customers are aware up-front of the obligation. One way to achieve this would be to tie the termination price to what KCP&L has to pay another customer to accept the remaining contract obligation, including the transaction cost to do so. This would be consistent with market liquidated damages as the termination fee. If no customer can be found, then the termination fee is the cost to acquire a comparable capacity contract from the markets. Of course, facing market realties will make longer-term contract less attractive, but that is the point KEMA is making by advising against heavy reliance of such instruments. Finally, KCP&L should limit the number of multi-year contracts to ensure a balanced and diversified portfolio, and stagger the terms so that they do not expire at the same time, which could result in problems finding replacement resources.

6.3 Optimizer

The Optimizer program is an operational program in which dispatchable thermostats are installed in residential facilities. We understand that KCP&L will expand this program to commercial facilities in this coming year. Review of KCP&L's program reports indicate that this program is on track to deliver 15.5 MW in gross capacity. For the purposes of SPP recognition, it is likely that this capacity will need to be derated to account for the fact that it is largely available only during the summer months. For the purposes of this analysis we are assuming that the de-rating factor would be 25% meaning that the gross capacity times 75% will equal the assumed delivered capacity. However, further analysis is likely to be required.

Figure 6-2 shows our estimates of the gross MW contribution of Optimizer during the study period. We have based the top row Base Case on our estimate of the current program trajectory. Our worst case assumes a drop off on program uptake and the Aggressive case assume additional efforts and incentives.

Table 6-2 Gross Optimizer contributions.

	2007	2088	2009	2010	2011
Base Case	19.6	24.8	29.4	31.4	45.0
Worst Case	16.6	18.1	19.6	21.0	20.4
Aggressive	26.6	31.8	36.4	38.4	60.0

7. Implementation Plans

7.1 Approach

The preceding analysis conducted by the KEMA team was conducted to determine the optimum portfolio of demand response and price response programs largely from KCP&L's perspective. Heretofore, we have largely focused on the economic issues pertaining to these programs. As we discussed in the previous sections to be successful, this portfolio must be paired with a well thought out and substantial marketing effort. In this section we offer thoughts on the key aspects of a strong effort. We begin by discussing your customer base with a particular focus on what their motivations are and how they would view offerings such as these. After this discussion we offer recommendations what form of marketing, education and training, and equipment will be necessary for the programs to be implemented. We also offer overall budgets based on our experiences with marketing rates and energy efficiency services.

7.2 Customer Characteristics

The following discussion is largely based on the KEMA team's experience with other markets as well as market research performed of various customer classes[31]. That being said, we have found no indications that KCP&L's customers have any unique attitudes pertaining to energy cost management. As with any good marketing effort KCP&L should test and fine tune its messages as it launches its marketing efforts.

[31] Some of this includes proprietary research that KEMA has performed for certain DR service providers.

7.2.1 Residential Customers

Characteristics

Our review of the demographics for the Kansas City MSA[32] and KCP&L's Appliance Saturation survey of Johnson and Jackson Counties[33] indicates that the vast majority of KCP&L's customers live in single family dwellings. Electric space heating only represents about 16% of the market and electric central air conditioning (A/C) is now in most dwellings. Roughly a third of the work force is in management, professional and related occupations.

A/C load is the main summer variable daytime load. Other loads such as pool pumps and electric hot water may be possible for some households; but they represent a small percentage KCP&L's customers. Hence much of the summer residential peak load is driven by air conditioning.

From a national perspective, attitudes towards conservation and energy efficiency tend to be positive. Recent surveys (Shelton Group, October 2006) noted that 61.9% of households believe that energy conservation is important. 65.2 % of respondents view "conservation" as a favorable term and 71.3% believe that energy conservation is important or very important.[34]

For most homes, there is an ability to shift loads to off-peak hours. Exceptions are relatively rare but common reasons for exceptions are medical or family members or pets remaining in the home throughout the day.

Motivations

Although KCP&L has a residential Time-of- Day rate for some time, it is our understanding that it has not been widely promoted and, therefore, most customers are unfamiliar with the concepts

[32] United States Census Bureau, 2000 Census Tables DP-1 through DP 4.
[33] 2004 KCPL Appliance Saturation Survey
[34] Results of a survey reported by the Shelton Group, September 12, 2006 at Alliance to Save Energy meeting in Washington DC. Full presentation may be found at http://www.ase.org/section/_audience/events1/summit

behind Time-of-Use rates. Typically, they have been under flat rate pricing and hence have not been exposed to price variations in electricity. Further, if national data holds true, we expect that the majority of homes owners do not have knowledge regarding how wholesale energy prices fluctuate during a typical day nor do are they expected to have knowledge of how energy market work.

However, based on our experience most homeowners believe that conservation is important. In addition, most families do try to save money and reduce their energy costs by conserving energy. Though a home may not have made the direct link to hourly wholesale prices, they most likely will readily accept the idea of having the ability to save money by shifting usage to off peak periods. In fact, pricing plans with cell phones may have educated consumers on time based rates.

When selling the program to the public, marketing campaigns should stress the conservation aspects of TOU pricing and the ability of homeowners to save money by shifting loads (laundry, A/C, clothes drying) to off-peak periods. The incentive to participate in the load is simply the opportunity to save energy and money.

Demand response will be viewed in a similar manner with some exceptions. Under the TOU rate, a customer can voluntarily shift usage and make conscious decisions at what points to shift. For Demand Response, they typically do not have the flexibility to use an appliance that has been turned down until the end of the demand response period. The installation of an automatic thermostat at no cost has been a strong incentive for many customers. Other motivations to participate also include the concept of contributing to the greater good and community.

Risk Factors for Customer

For the majority of homeowners, shifting load typically is not problematic. However, some homeowners will have mitigating circumstances such as medical (certain members of the family home all day and need summertime cooling) or keep pets inside during the work day. For these homeowners that are not able to shift load, some will object to the rate if their overall energy costs rise by shifting to a new rate. However, for the majority, most homeowners will not have many risk factors to take into account. Tenants are somewhat more problematic in that they shorter occupancies and may have limitations as to how the participate.

The main inhibitors to joining programs are typically "hassle factors" or the inconvenience of required actions or disruptions to normal routines that may discourage use. For example, if the TOU rate is viewed as burdensome (i.e. too many on-peak hours) to the point where a great deal of usage needs to be shifted to off-peak hours, there may be too many disruptions in normal routines for the program to be of value.

For Demand Response, if the program is called too often or typically lasts much longer than anticipated, then program success is put at risk. Marketing surveys and feedback mechanisms can ensure attitudes toward the programs remain positive.

7.2.2 Commercial Customers

KCP&L has a high proportion of commercial customers compared to many other LSEs. Therefore, focus on small and medium general service customers will be important.

7.2.2.1 Small General Service

Characteristics

Small general service customers are usually boutique shops or small convenience stores. Their usage is typically during the day – normal business hours – and Monday thru Saturday.[35] Their energy usage is focused on selling to customers of their business or simply stated as "cash register" issues (quality lighting and temperature control). The factor that the customer class is operating a business and the success of that business depends on the service provided to customers creates larger risk factors for this customer class. When marketing to this customer, attention needs to be focused on motivations and risk factors more than perceptions and attitudes of the business owners.

Motivations

Most of the focus of businesses is on cash register issues and not on energy. Hence, saving money on the energy bill and conservation will have a much lower priority than not disrupting customer traffic for potential business and sales. Some businesses will be open to campaigns where it is publicized that the business is participating in a program that will help the area and conserve energy, but only if they believe it will improve business.

In addition, for business owners, the savings that can be generated by participating in energy savings program, for the size of the total electric bill, are small when compared to sales.

Risk Factors

As small business customers are typically single shift, Mon-Saturday, 10-6 PM, their normal business hours will fall during peak-pricing periods. In addition, the rate payer will not be able to enjoy the benefits of off-peak pricing as businesses may not be open during that period. Finally, this particular customer will most likely have little flexibility in shifting loads. Hence, this customer class will have the main risk of their energy bill increasing and hurting profits. On

[35] Convenience stores and other retail businesses that have longer hours will tend to have usage and demand that puts them in the Medium GS level.

the whole, this customer will be accepting of the shift in rate structure only if they can remain cost neutral when compared against their previous rate.

7.2.2.2 Medium General Service (26 kW to 200 kW)

Characteristics

Typically this customer class breaks down into small businesses such as retail chain stores (fast food, restaurants, and specialty stores) and government buildings. Loads are dominated by HVAC, refrigeration, Lighting, and electric heating when applicable.

Much of the same cash register issues apply to this customer class as with small general service. However, there are a couple of factors that separate this level of customer.

These customers are large enough that some have energy management systems or controls. Hence, the customer sophistication level, understanding of energy usage and energy costs is much greater than smaller rate classes. As a result, this customer has the ability to make adjustments to usage patterns. In addition, if the customer is a retail chain store, their corporate headquarters often have energy managers that are familiar with the rates and tools that are needed for the business to save money on the rate or to operate effectively under the rate.

Finally, as these stores are typically larger, their hours of operation are much wider and will be able to see benefits from off-peak hours.

Motivations

For pricing programs, the increased level of sophistication of the customer will allow for innovative means to reduce costs. However, cash register issues and customer service levels will remain the highest priority for the customer class. This factor comes into play more for demand response programs than pricing programs.

With regard to small production facilities, those that have flexibility in their operations will also prefer the pricing programs and will look at the tariffs as an opportunity to save money and reduce costs. For facilities that do not have flexibility, such as critical care, they will simply look for consistent costs.

Given a choice of tariffs that are cost neutral, they will choose the tariff that requires the least amount of manpower to manage. Facilities are also interested in being able to plan production in advance. If a pricing program contains too many unknowns as far as the potential yearly cost of energy, the facility will not be too interested in the program

For demand response programs, acceptance of the program has a greater impact and a higher hurdle to motivate this customer class into participation. Unlike pricing programs, where smart energy management can maximize potential savings, demand response programs can disrupt operations. More importantly, for retail chains, where the dominate motivation is the cash register, the customer may have zero motivation to participate. Even with controls and sophistication, even a small probability of a problem creating an impact to sales is often too great for consideration.

Risk Factors

Pricing programs and demand response programs have the potential to offer the customer the ability to save money on their energy bills. The ability to extract savings will be weighed against potential risk factors that may be involved in the process. For pricing programs, the main risk factors will be (1) increased cost of energy (operations) if the tariff is not properly managed, (2) decreased ability to plan yearly energy costs in advance if going to full pricing programs, (3) the fact that actions will need to be taken (manpower costs) to keep costs neutral and whether those actions will impact production or services provided. These risk factors will be weighed against the potential savings that can be achieved, the costs required to achieve those savings, and whether the savings equates with the risks associated with the tariff.

For demand response programs, the main risk factors are (1) disruptions in customer service, traffic flow, and sales for the day, (2) equipment disruption from load shedding leading to long term outage or facility problem. Typically, for the size of the energy bill, the incentives and savings are not high enough to overcome what is weighed as very high risk factors. Often, flexibility of pricing and demand response programs need to be applied in order to overcome risk factors viewed by this customer class.

7.2.2.3 Large General Service (201 – 1MW)

Characteristics

Large General Service customers tend to be a mix of all types of business and customers. The types range from retail (e.g. supermarkets), government and municipal buildings, small industrial, hospitals and assisted living homes, and hospitality. One of the main characteristics between this customer class and medium general service is that these customers tend to operate on multiple shifts. Though these business are selling services and hence have an obligation to maintain service, they tend to have a great deal of flexibility (outside of critical care) to shift load and take advantage of the rate offering. Loads are dominated by HVAC, refrigeration, and Lighting.

These customers are large enough that often times they have energy management systems and controls. Their energy usage would be very well understood and their loads varied enough to provide flexibility.

For industrial customers, their key concerns are focused on production issues. Hence, depending on the number of operations running and the number of shifts, flexibility may or may not be present.

Motivations

Owners and energy managers more likely have a very accurate assessment of their energy use patterns. Hence, they will quickly be able to understand whether the load will increase their costs, require actions, or simply allow them to save money by making adjustments. In addition, it is recognized that redundancy in some systems provide an opportunity to reduce load or shed load during critical or peak periods. Hence, this customer class, though also focused on customer and cash register issues, tend to have flexibility in their operation to take advantage of pricing programs and demand response programs.

Risk Factors

Pricing programs and demand response programs have the potential to offer the customer the ability to save money on their energy bills. The ability to extract savings will be weighed against potential risk factors that may be involved in the process. For pricing programs, the main risk factors will be (1) increased cost of energy (operations) if the tariff is not properly managed by the customer, (2) decreased ability to plan yearly energy costs in advance if going to full pricing program means that rates move with market prices, (3) depending on the program that actions may need to be taken (manpower costs) to keep costs neutral and whether those actions will impact production or services provided. These risk factors will be weighed against the potential savings that can be achieved, the costs required to achieve those savings, and whether the savings equates with the risks associated with the tariff.

For demand response programs, the main risk factors are (1) disruptions in customer service, traffic flow, and sales for the day, (2) equipment disruption from load shedding leading to long term outage or facility problem if not correctly controlled. Typically, for the size of the energy bill, the incentives and savings are not high enough to overcome what is weighed as very high risk factors.

7.2.3 Large Power (> 1 MW)

Characteristics

Large Power customers are typically industrial, large institutional and critical care (hospitals). For industrial customers, factors are focused on production issues. Hence, depending on the number of operations running and the number of shifts, flexibility may or may not be present. These customers generally have energy management controls and energy managers present at the facility and understand the impact energy costs have on their business. In addition, they will have the ability to assess their historical usage and the impact a new tariff will have on this operations.

Industrial facilities are always looking for a means to reduce costs and improve profits. If the tariff allows the facility to accomplish this task without significant impact to production and operations, the tariff should be very appealing.

Motivations

For facilities that have flexibility in their operations, they will look at the potential of the tariff. For facilities that do not have flexibility, will simply look for consistent costs.

The main motivation for industrial production facilities is to continually look for ways to reduce costs at a minimum impact to production. Given a choice of tariffs that are cost neutral, they will choose the tariff that requires the lowest transaction costs compared to potential benefits. Facilities are also interested in being able to plan production in advance. If the tariff contains too many unknowns as far as the potential yearly cost of energy, the facility will not be too interested in the program

If the alternative tariffs constitute an increase in pricing, then the facility will look to examine ways to utilize the tariff to help reduce costs. Owners and energy managers most likely have a very accurate assessment of their energy use patterns. Hence, they will quickly be able to understand whether the tariff will increase their costs, require actions, or simply allow them to save money by making adjustments.

Risk Factors

Pricing programs and demand response programs have the potential to offer the customer the ability to save money on their energy bills. The ability to extract savings will be weighed against potential risk factors that may be involved in the process. For pricing programs, the main risk factors will be (1) increased cost of energy (operations) if the tariff is not properly managed, (2) decreased ability to plan yearly energy costs in advance if going to full pricing programs, (3) the fact that actions will need to be taken (manpower costs) to keep costs neutral and whether those actions will impact production or services provided. These risk factors will be weighed against the potential savings that can be achieved, the costs required to achieve those savings, and whether the savings equates with the risks associated with the tariff.

For demand response programs, the main risk factors are (1) disruptions in customer service, traffic flow, and sales for the day, (2) equipment disruption from load shedding leading to long term outage or facility problem. Typically, for the size of the energy bill, the incentives and savings are not high enough to overcome what is weighed as very high risk factors. Often, flexibility of pricing and demand response programs need to be applied in order to overcome risk factors viewed by this customer class.

7.3 Specific Concepts for Individual Pricing and Demand Response Programs

Though some of the actions and approaches are similar for all classes of programs and many of them will be marketed under a common umbrella or by a single KCP&L representative. There will also be differences and the following discussion is intended to illuminate those as well as offer thoughts on budgeting and staff that is required.

The common theme among implementation of new programs, tariffs, or demand response initiatives is that the key is to market the program continuously. Though all stakeholders involved in the energy industry have a thorough understanding or energy markets and pricing, a large majority of the public is unaware of the intricacies of energy and in general are resistant to change. A summary of the individual programs and details are supplied below:

7.3.1 Pricing Programs

TOU – Time of Use Pricing Program - TOU for All Customer Classes

Objective:

The Time-of-Use is the easiest rate for a customer to understand and it is, also, from the customer's perspective the least risky as all the prices are published. However, from the utility perspective there is some risk of revenue loss if enough load is shifted to result in lower marginal costs during high priced periods.

Overall Description of rate:

Section 4 examined the suggested details and economic motivations of the Time-of-Use. To summarize, this rate has three main factors that are used when considering the pricing structure. These factors are (1) Number of periods to consider during each day, (2) Length of time of each period during each day, (3) Number of months during the year for a specific period to be active. For TOU rates, the details around each of the factors and the price charged during each of the periods are published in advance. In designing the rate, have the duration of the high priced periods from 2 p.m. through 6 p.m. June through September. This mix of time and season allows an adequate difference between on and off-peak prices to be of interest to the customer while providing benefit to KCP&L as well. A significant change from the current offering is that this will be offered to all classes of customers.

Customer Impact:

For the KCP&L customer, its motivation to use the rate is in achieving potential costs savings from any change in their energy load. If a customer has the flexibility to alter their usage patterns and shift load to off-peak hours, then the rate can be very beneficial for the customer. This scenario fits with residential profiles. However, for an industrial or commercial business, if they are single shift companies operating from 9-5 PM on weekdays, then the switch to the rate may create a burden for the customer depending on what the seasonal off peak rates are. One key component to the rate – prices and periods published in advance - has the advantage of allowing the customer to plan costs and hence the customer does not face any risk factors with varying prices. *With this in mind, the Time-of-Use rate should reasonably with Residential, Medium, Large General Service, and Large Power customer classes. Small General Service, because of the typical hours or operation, may have difficulty with the rate because of the tendencies towards single-shift, weekday operating hours.*

Target Markets:

The target market for KCP&L will be across all rate classes in both MO and KS. That being said, residential customers will seem to have the greatest flexibility in shifting loads to off-peak hours. If marketed correctly, they most likely will welcome the opportunity to shift their usage and bring an element of control over their electricity bills.

For business class customers, whether large or small, they may have flexibility to react during a short period of time. However, with peak period rates extending over months, customers will essentially be paying higher prices during the summer months for energy. Whether this becomes a neutral cost factor for a customer because of a comparatively lower off peak seasonal rates will depend on their usage patterns and operating hours. Overall, most customers will accept the change and push back if the change results in an overall increase in their power costs.

Market Strategy:

Like all new programs, education and marketing is the key for gaining acceptance of the program. This education of the customer base will need to be across the board and require training of key account reps and well as customer service reps / call center representatives.

Implementation will vary depending on customer classes and will require direct marketing for residential and small commercial customers. For large commercial customers, the education and training will need to focus on informing businesses on the details of the rate. This education will need to focus on how the average, yearly cost of energy will not change for the customer, but they most likely will be paying higher costs during the summer months than during the winter months. In this sense, the customer will still have a predictable energy pattern and maintain the ability to accurately plan yearly expenses.

As the rate also does not require dynamic interaction from a customer, the level of customer education will be less than the other pricing programs. The main motivation for the customer is to know that they will be able to save money if they shift away from consuming power during peak periods and that the purpose of the program is to more closely link energy prices to actual costs.

As the rate is being recommended to apply across all rate classes, the type of marketing required will change as the customer size increases. For Residential, Small General Service, and some Medium General Service customers, a direct mail, mass marketing campaign will be required. Marketing is typically conducted through direct mail and telemarketing campaigns. It will often be supplemented with special events, radio spots and newspaper advertisements. Further, the use of Internet based analysis tools to assist customers are increasingly being utilized. Of course, it will be important for the information material to have a number for potential customers to call in order to answer additional questions; hence training will be needed for call center representatives.

For larger customer classes, a more direct sales approach will be required through key account reps. Representatives will need to be aware of how the different pricing rates will affect a business and actions that can be taken to optimize the rate for the end-use customers.

Education & Training Activities:

Training will focus on the Key Account Representatives to provide the representatives with the ability to "sell" the rate and answer questions that there large customers will most likely be asking. As they questions will focus on the risk implications of the higher summertime peak rates, the representative will need explain how those increased rates will be countered by lower off peak rates. In addition, representatives will also need to explain the advantages offered by more closely linking their energy rates to market prices.

As the program becomes targeted towards a large customer base, the main goal is to ensure the rate rules are published, stable, simple to explain, and that call center operators understand the advantages and any risk factors to answer questions presented to them by all customer classes.

B. Real-Time Pricing Program

Objective:

The objective of the Real-Time Pricing (RTP) program is to provide a more direct link of energy prices to actual wholesale market prices. In addition, because customers are able to gauge when prices are rising to unacceptable levels, a price based incentive is provided to customers to reduce their loads during this time. In this sense, the RTP pricing program acts as a price-based load reduction program. By exposing the customer to the wholesale prices of electricity, customers are given the incentive to reduce load or shed load during that time in order to avoid paying premium power prices for that period.

Because prices are only published a day in advance and their predictability is only based on historical averages, RTP will be viewed as riskier by all classes of customers and significantly more customer education will be required. The rate generally will resonate better with more sophisticated customers who will often be the larger customers as they are typically sophisticated energy users and oversee operations that are flexible enough to alter their energy usage if it is known that they will be exposed to premium prices. By avoiding usage during high peak price periods or shifting usage to periods of low hourly pricing, the customer will be able to save money off their normal energy bill.

Description:

Overall Description of rate:

Like the TOU case, KCP&L already has a RTP rate. The KCP&L rate has taken into consideration some of the risk factors associated with the general concept of the rate and provided adjustments. The Real-Time Pricing program links hourly wholesale electricity prices to hourly charges to the customer. Instead of operating on a rate that is based upon an average price per period, the customer is exposed to hourly prices and thus linking them directly to real-time market signals. Under a RTP tariff, a customer is given notice of the pending pricing and then adjusts its usage accordingly. However, the ability to view pending increases in hourly prices allows the customer to change the usage patterns and save money by using the tariff.

Customer Impact:

For the KCP&L customer, their motivations are to in achieve potential costs savings and to assist KCP&L in controlling its costs for the greater good of the community. As the highest prices will typically fall during critical periods, the program does act like a critical peak pricing program except for in the case of RTP, it is up to the market to set that peak price.

The costs savings are achieved not by reducing their yearly consumption but rather by shifting usage during the higher real-time peak pricing periods to off-peak periods. Though this is similar to the TOU motivations, the hourly peak prices tend to be higher than the average price of the TOU rates, thus providing a stronger motivation to shift usage and a greater "cost" penalty for the customer for not shifting usage during the period.

The benefit gained by assisting KCP&L during emergency situations is a market driven process. If KCP&L starts to face an emergency supply problem, customers may see the hourly prices spike higher in response to the unexpected increase in demand. In order to avoid the price spikes, customers will then cut back on usage and thus lower the demand during that period. That lower demand will then be reflected in the hourly prices and usage decreasing, lowering the risk of system problems occurring.

It can be assumed that compared to a typical TOU rate, real time prices will be lower than expected during off peak hours and may be higher than pre-published averages during peak hours. However, there is potentially a large risk factor if supply and demand issues force a spike in prices. If the customer does not have the ability to respond by either shedding load or using back-up generation, the customer can potentially face a large increase in energy costs.

In addition, there is another potential new cost for a customer that does not have an energy manager or people dedicated to monitoring energy usage. To successfully respond to RFP rates, a customer will need to monitor day-ahead prices and switch production or activities in response to the signals. For residential customers this will require providing them tools to monitor and understand their usage in order to make changes. For firms that do not already posses energy managers or have inflexible production schedules, this rate does not add much value to their company. It is for this reason that RTP rates tend to work well for large customers as they typically have the monitoring systems and personnel already in place. However, recent experience with residential customers in Commonwealth Edison's service territory in Chicago indicates that RTP rates can and will be accepted by residential customers as well with the appropriate support.

With appropriate education customers will understand the risk associated with the rate – mainly that they can be exposed to market swings and get unexpected spikes in energy costs. In addition, savings potential of "shopping wholesale" may be tempered by effort to shop wholesale - monitoring prices and shifting of routines to respond to peak price notices.

Customers may ask for ability to hedge their risk with Real-Time Pricing programs in order to participate in the tariff. KCP&L has taken this into consideration with their RTP program. KCP&L utilizes a "Two-Part" real-time pricing program. For these programs, a KCP& L establishes the customer's a base load usage profile that is charged to the customer at specific on-peak and off-peak rates. Usage above that profile is charged to the customer at the real-time or hourly price. The base load portion of the customers' bill acts as a hedge while still encouraging the customer to use less energy during peak pricing days. For the utility, this ensures that spot energy prices that are purchased above the normal load prices are charged through to the customer and not absorbed by the utility.

<u>KCP&L Impact:</u>

For KCP&L, there is limited risk, expect for the additional potential costs for customer service and support, as customer charges are closely to hourly prices. In fact, the program essentially shifts most of the risk of unexpected price swings directly to the customer. Though not acting as a load reduction tool for emergency situations, the tariff does encourage load reductions during high peak prices and larger load reductions than seen under standard TOU pricing tariffs.

Target Markets:

The target markets for the real-time pricing program are all customer classes with a particular emphasis of those who are sophisticated buyers and monitor and respond to daily pricing. The factors that determine a strong customer are the following:

1. Dynamic nature of the pricing signals and actions required to monitor and respond to the pricing signals require a level of sophistication possessed by large customer classes. For customers that have the ability to respond to price signals, the program can make sense because on the whole, the hourly prices will result in a lower overall cost for the customer. If a customer already has an energy manager in place or the ability to monitor signals and flexibility to respond, then the program can become beneficial.
2. Ability to handle risks of tariff. The main inhibiting factors preventing customers from switching to RTP is the risk of a higher energy bill. Customers can be exposed to this risk because they either don't respond to rising hourly prices or are unable to respond
3. Ability to shift activities and not impact overall business. Small customers typically do not conduct multiple tasks during the day. Hence, they have limited ability shift usage. On the other hand, large customers tend to operate multiple shifts and multiple tasks. If the customer has the flexibility to quickly alter, then they can respond to price spikes more readily.

These attributes are typically found in customer classes that equate to KCP&L Medium General Service, Large General Service, and Large Power Customer classes. Residential customers with Internet access who have demonstrated interest in the program by using KCP&L's analysis tools would also be a good target.

Business Customer Motivations:

Business customer motivations are always centered on whether the service can reduce their energy bill and costs. The real-time pricing rate does not involve load reduction or required load reductions at a specific time; hence, there are no capacity issues that can potentially affect a daily operation. This factor tends to motivate a business customer to want to participate in a program that potentially allows the business to react to actual market prices and control their energy costs.

However, in order to take advantage of the real-time pricing rate, a company will need the ability to monitor, respond to dynamic changes, and mitigate risk factors tend to decrease. As the size of a company decreases, there are typically fewer of these factors present and a company will be more exposed to risk factors such as a single day price shock or peak period price rises. Hence, the ability to lower their energy bill will be measured against the risk of an unexpected price shock that could potentially consume any savings that may have been gained during normal operations and normal hourly pricing.

By examining the motivations and realities, it can be concluded that in order to increase participation in such a program, any means that can lower the risk factor with the rate will most likely extend the participation levels into lower business classes.

Market Strategy:

As the program will most likely be a new tariff for customers and require interactive participation on the part of the customer, a strong education effort needs to be conducted up front. Initially, this process should be easier as the targeted customer class can be marketed with Key Account representatives. It will be important for these representatives to inform the customers on how the tariff works and expected actions that need to be taken in order to successfully profit from the tariff. Finally, feedback from customer comments needs to be gathered in order to assess the initial reaction to the tariff.

The first introduction of the tariff should be voluntary in order to allow KCP&L customers who are willing to utilize the rate to test the rate out. The reaction to the rate can be measured by participation from the customer base. Once again, feedback will be a critical requirement in determining whether customers are finding the rate of value or whether changes need to be incorporated such as the ideas of Two-Part Real Time Pricing or some type of KCP&L price hedging.

As customers become more accustomed to the rate and adjustments are made to the rate structure, expansion of the rate can be considered. As the Key Account reps and call service representatives become more educated on the rate, a larger roll-out of the rate to medium general service can be considered. As this rollout will involve direct marketing campaigns, education, simplicity, and a finalized rate approach for real-time pricing will need to have been incorporated before the rollout occurs. It is important that the rate be in its finalized structure before it is rolled out to medium level customers because as the program becomes a more mainstream with direct marketing efforts, any additional changes could potentially increase confusion and provide hurdles to letting the new customer understand the offering.

Coordination with Other Efforts:

Since RTP is part of an integrated offering of pricing and demand response programs it should be offered in conjunction with the other programs so that customers may select the offering that is best for their individual circumstances.

Education & Training Activities:

Training will focus on the Key Account Representatives to provide them the ability to "sell" the rate and answer questions that there large customers will most likely be asking. As they questions will focus on the risk implications of the real-time pricing program, the representative will need to also understand the factors and action necessary for a customer to take advantage of the rate and mitigate potential risk factors.

As the program becomes targeted towards a large customer base, the main goal is to ensure the rate rules are final, simple to explain, and that call center operators understand the advantages and risk factors to answer questions provided by medium general service customers.

VPP for General Service & Large Power Customers

Objective:

Variable Peak Pricing Program is a combination of TOU and RTP rates. Under VPP tariffs, the peak period provides an opportunity to more directly link wholesale markets to retail rate pricing. As this price reflects actual market prices, the rate provides a mechanism for the utility to have their customers respond to unexpected or high prices during peak periods. For a Variable Peak Pricing program, the price that is charged is a variable rate that is determined from day-ahead prices or locational marginal prices (congestion points). The objective of the rate is to provide an additional price responsive load reduction tool for KCP&L to use for their customer classes.

This program offers another alternative to KCP&L customers to demand response or curtailment programs and provide larger load reductions for KCP&L than standard TOU rates. By providing "high" peak price periods through a short notice notification process, customers can respond much like a typical load control program and provide KCP&L with greater peak load reduction.

Description:

Overall Description of rate:

The Variable Peak Pricing program is typically layered into the Time-of-Use rate structure and is structured along the same basis as the time-of-use rates. The main feature of the VPP rate and how it differs from the standard TOU rate is that during specific "critical" peak periods, prices can be a great deal higher than TOU peak prices. This increase in price for critical periods is balanced by a reduction in the base load "off-peak" rate. The increase in price for the peak period is intended to encourage customers to shed load during the peak period and avoid using as much energy as possible during the period.

Customer Impact:

For the KCP&L customer, their motivation is in achieving potential costs savings and assisting KCP&L to help avoid emergencies on the grid. Though this is similar in concept to the TOU motivations, the peak pricing provides a stronger motivation to shift usage and a greater penalty for not shifting usage during the period. The benefit gained by assisting KCP&L is to allow the customer to take actions that can help avoid blackouts or long term outages.

KCP&L Impact:

For KCP&L, the VPP program provides an additional load shedding tool that is not provided by a TOU rate. As the program allows customers to react on short notice to prices signals and shed load, the program essentially acts as a demand response tool for the utility. In addition, the program allows the utility to be more fairly compensated when wholesale electricity prices rapidly increase due to contingencies or emergencies on the system. The VPP rate also is intended to be revenue neutral or positive for the utility as load is only being shifted from one period to the next. The cost savings that are gained by the customer from shifting load out of the critical pricing period to the lower off peak pricing period will be made up through savings that the utility gains by the ability to shed load and avoid system emergencies or the need to purchase wholesale power at high peak prices.

Target Markets:

The target markets for the VPP pricing program are similar to the RTP target markets. These targets are the large customer classes where sufficient load is likely to be available to curtail.

The factors that make these customer classes good targets are similar to the RTP factors and are the following:

1. Dynamic nature of the critical pricing signal and rate: The signal for when the period is going to occur is dynamic and responding to it requires a level of sophistication possessed by some large customer classes. For customers that have the ability to respond to price signals, the program can make sense because on the whole, the hourly prices will result in a lower overall cost for the customer. If a customer already has an energy manager in place or the ability to monitor signals and flexibility to respond, then the program can become beneficial.
2. Ability to handle risks of tariff: The main inhibiting factor for a customer is the risk of not being able to respond and shed load during the critical period. The inability to respond will expose the customer to spikes in their energy bill because they either don't respond to rising hourly prices or are not able to respond. Large customers typically have processes in place to mitigate the risk factor.
3. Ability to shift activities and not impact overall business. Small customers typically do not conduct multiple tasks during the day. Hence, they have limited ability shift usage. On the other hand, large customers tend to operate multiple shifts and multiple tasks. If the customer has the flexibility to quickly alter, then they can respond to price spikes more readily.

<u>Business Customer Motivations:</u>

Business customer motivations are always centered on whether the service can reduce their energy bill and costs as well as the risk associated with the potential reduction. As the VPP essentially acts as load reduction or requires load reductions at a specific time, the customer will carefully examine the risk associated with the events to determine the impact on their costs and operations.

As with the RTP program, a customer will need the ability to monitor and respond to dynamic price signal in order to successfully work with the rate. As the size of a company decreases, there is typically less ability to respond in a sophisticated manner and the company will be more exposed to risk factors such as a single day price shock or peak period price rises. Hence, the ability to lower their energy bill will be measured against the risk of an unexpected price shock that could potentially consume any savings that may have been gained during normal operations and normal hourly pricing.

By examining the motivations and realities, it can be concluded that in order to increase participation in such a program, any means that can lower the risk factor with the rate will most likely extend the participation levels into lower business classes.

Market Strategy:

Like all new programs, education and marketing is the key for gaining acceptance of the program. This education of the customer base will need to be across the board and require training of key account reps and well as customer service reps / call center representatives.

Implementation will vary depending on customer classes and will require direct marketing for residential and small commercial customers. For large commercial customers, the education and training will need to focus on informing businesses on the details of the rate. This education will need to focus on how the average, yearly cost of energy will not change for the customer, but they most likely will be paying higher costs during the summer months than during the winter months. In this sense, the customer will still have a predictable energy pattern and maintain the ability to accurately plan yearly expenses.

As the rate also does not require dynamic interaction from a customer, the level of customer education will be less than the other pricing programs. The main motivation for the customer is to know that they will be able to save money if they shift away from consuming power during peak periods and that the purpose of the program is to more closely link energy prices to actual costs.

As the rate is being recommended to apply across all rate classes, the type of marketing required will change as the customer size increases. For Residential, Small General Service, and some Medium General Service customers, a direct mail, mass marketing campaign will be required. Marketing is typically conducted through billboards, naming of the program, and radio ads. It will be important for the information material to have a number of potential customers to call in order to answer additional questions; hence training will be needed for call center representatives.

Coordination with Other Efforts:

As this is a stand alone pricing program, little coordination with other efforts will be required. The VPP Program is typically overlaid onto a TOU rate. Hence, some coordination can be conducted with the rollout of the TOU programs and customers that are currently under the TOU program.

Education & Training Activities:

Training will focus on the Key Account Representatives to provide the representatives with the ability to "sell" the rate and answer questions that there large customers will most likely be asking. As they questions will focus on the risk implications of the higher summertime peak rates, the representative will need explain how those increased rates will be countered by lower off peak rates. In addition, representatives will also need to explain the advantages offered by more closely linking their energy rates to market prices.

As the program becomes targeted towards a large customer base, the main goal is to ensure the rate rules are published, stable, simple to explain, and that call center operators understand the advantages and any risk factors to answer questions presented to them by all customer classes.

Budget Consideration:

A key component to the rate will be the monitoring equipment required for a customer to view day-head or real-time prices. A key component to the rate will be a meter capable of measuring interval data. Our team has noted that KCP&L has CellNet meters for over 97% of their customers. For $12.95 per month, KCP&L will be able to read interval data for the specific month of the TOU peak pricing period. Hence, this number will need to be included in the program costs for customers in the lower rate classes.

If this equipment is not already present, a customer will need to include the cost of the equipment into their decision process on whether to switch to the rate.

7.2.4 Reliability and Capacity Programs

There are three programs that are proposed for reliability and capacity purposes. The Direct Load Control program (Optimizer Plus) and MPOWERPlus programs will meet the SPP requirements for capacity reserves. The Voluntary Load Reduction program is not expected to qualify and, as such, should be viewed as providing load reduction during critical periods.

7.2.5 Energy Optimizer

Program Objective

The objective of the "Energy Optimizer" demand control program is to reduce peak load by curtailing air conditioning in the residential sector at peak usage times. Additionally, the program's programmable thermostats may assist customers in more efficiently managing their energy use.

The peak energy usage period during which curtailment could occur is May through September. The program installs the controlled programmable thermostats throughout the year.

KCP&L estimates 1.2 kW savings per household. KCP&L plans to have a total of 15.5 MW gross capacity in place by the end of 2006.

Program Objective

In return for a free Honeywell ExpressStat™ programmable thermostat (valued at $300), plus free installation, the residential customer agrees to allow KCP&L to raise the temperature in their space during event periods. The thermostats that are currently installed are one-way devices that are accessible to the curtailment team using a radio frequency control system that acts like a pager. Customers who are planning a special event can be removed from the program up to three days each summer by contacting the program call center in advance.

Existing Program

This program is a continuation of an existing program that was initiated in 2005. This initial budget permitted KCP&L, with the support of their implementation contractor Honeywell/DMC (DMC), to install approximately 12,000 programmable thermostats during the period. The program's current average installation and program cost is approximately $500 per site. By KCP&L's estimates this program is has benefit to cost ratio of approximately 1.1.

Target Market

All KCP&L residential customers with central air conditioning or heat pumps that are in good working order are eligible for the program. Newer homes, homes with upgraded insulation, or homes that are well shaded will benefit the most from the program because they will have the least internal temperature impacts during the cycling. Homes with window air conditioning units as the only cooling system are not eligible.

We propose that KCP&L offer the program programs to small commercial sector customers as well. The commercial market should be a long-term program expansion consideration. The advanced program design features a more ramped up Optimizer program which should incorporate commercial markets. KCP&L should also consider an offering to the multifamily market. The commercial Optimizer component should be added in 2007-8 of the program although adding this service earlier is an option if commercial customers express interest in the program.

KCP&L could initially test interest in the small commercial program by implementing a small pilot program in 2007. We recommended that KCP&L enhance the program targeting approach to maximize recruitment efficiency. A more comprehensive targeting effort could include leveraging customer billing data to identify potential target customers.

Eligible Measures

The program's primary measure is a one-way programmable thermostat that is used to control customer air conditioners as a load control device.

As best practices review in California suggest that controlling other equipment in addition to the air conditioner is cost effective. This is because the biggest program cost is the marketing and the added installation cost is minimal if done with the thermostat installation. Electrically heated domestic hot water is the other primary equipment to consider for additional cycling. KCP&L should implement a pilot Energy Optimizer domestic hot water program in year 2 or 3 and assess the effectiveness before embarking on a larger program.

Pool pumps are another consideration as an added measure. Although KCP&L appliance saturation data indicate that they are present in only in a small number of homes and, therefore, do not, not have a significant customer impact and are, therefore, often have marginal cost-effectiveness.

Implementation Strategy

KCP&L should continue to test its curtailment strategy regularly. In order to provide continued information to potential customers, KCP&L needs to develop and provide appropriate customer education materials. KCP&L should also add some verification services to insure that equipment is performing properly.

While the immediate implementation strategy is to continue to grow customer installations, KCP&L may assess the need to focus some portion of the program on customer retention through education, ongoing customer communication, and customer satisfaction surveys.

Marketing Strategy

For the current Optimizer program, most of customers heard about the program through direct mail solicitations. Direct mail should continue to provide a majority of lead generation activity. KCP&L should host and participate in discussions with HVAC contractors as well as offer training and program overview meetings. Contractor communication efforts may also make inroads with the marketplace and broaden acceptance of the program among critical constituents. Creating positive allies will continue to help provide additional lead generation and market acceptance opportunities.

The marketing materials should be updated annually. Customer service representatives should be trained in the program if that has not already been done. KCP&L should continue ongoing marketing efforts and focus a 2007 marketing campaign in the spring with additional materials available for flexible mailings as the program interest ebbs and flows.

KCP&L could increase the marketing of this program to increase installations by ___ per year. This is explored as an "aggressive" budget case later in this section.

Incentive Strategies

The programmable thermostat is the only incentive offered as part of the program. This is consistent with the best practices review, which states that most programs are able to meet their program objectives by providing the free programmable thermostat as the only incentive. While the program should continue with its current structure, the best practices review highlights that incentives are often necessary as the participation rate slows. The program implementation success rates will thus need to be regularly monitored to help identify if incentives need to be added in the future. At the time incentives may need to be offered, the best practices review suggests that KCP&L should start by offering other efficiency products such as compact fluorescent bulbs.

KCP&L should consider the possibility of creating special energy rate structures for customers who participate in the Energy Optimizer program. Alternative rates will help market the program more effectively and may be an important selling point for commercial customers once they are added into the program.

Coordination with Other Efforts

In order to effectively operate this program, program staff needs to coordinate efforts with the systems operations group to create a curtailment plan. The program staff must also coordinate with the customer support services to insure that call center staff are aware of program marketing efforts, curtailments, and complaint resolution procedures.

Coordination with HVAC contractors will continue to improve the effectiveness of co-marketing as well as insuring that contractors are aware of what to do in the case that they come across a thermostat in a customer's home. All thermostats should be affixed with a program contact number so contractors have a contact point to call with questions about the program.

Trade Ally Strategies

HVAC contractors are the primary trade allies and as noted above the program should coordinate with them regularly. Coordination should include program information workshops, contractor breakfasts, and ongoing communication. KCP&L should make efforts to participate in contractor association gatherings to promote the program and answer questions. KCP&L may want to consider creating a contractor referral network. HVAC contractors could be listed as a link from the KCP&L program website. The contractor list could include information on those contractors who have participated in KCP&L training and/or met KCP&L requirements. Because contractors are not directly performing the installations, the contractor list might not be appropriate but could help create a market resource for contractor referrals.

Education and Training

HVAC contractor training needs are minimal in content and should primarily be done as an education and awareness campaign. A "program information workshop" format is an appropriate format and may work well as a contractor breakfast. Workshops should occur at least twice a year, but may decrease as the market is made aware of the program and contractor acceptance improves.

Joint Marketing with Other programs

It is anticipated that the marketing of this and other residential and small business customer programs will be done in conjunction with other offerings. This program could also be market as a tool to respond to time of use pricing where appropriate.

7.2.6 Voluntary Load Reduction

Objective:

The VLR program key objective is to obtain reductions in customer demand during critical (emergency) periods when operational conditions are improved if load is reduced .

Description:

This is an enhanced version of the current VLR rate. Its key attributes are:

- Available to customers with a maximum demand of 100 kW or more
- Contract term is one year
- Customers sole discretion regarding the decision to reduce load
- Event season – Annual
- Customers provided two hours of notice of each curtailment request
- Event duration – at least two hours
- Event Payment: $0.50 per kWh for verified performance
- CBL: Dynamic hourly value that incorporates the most recent historical load, with an optional adjustment for current weather conditions
- Event kWh: the kWh represented by the difference between the actual load during an event and the CBL by hour
- Non-response penalty: none

Key differences from the VLR offering are:

- The curtailment option will be available for the entire year not limited to the summer season.
- The customer base load will be calculated using the most recent historic loads with weather adjustments.
- Given that this program a voluntary program and does not qualify as capacity under SPP rules we recommend that the payment to cover the development of curtailment plans be funded under MPOWER + not this program.

Target Markets:

This program will be available to commercial and industrial customers who have the ability to shed at least 50 kW. Our expectation is that most subscriptions will come from large industrial and institutional customers; however, there may be instances where smaller customers can offer worthwhile curtailments.

Market Strategies:

VLR will be promoted in conjunction with MPOWER where MPOWER will be described as the KCP&L offering that provides the most savings. VLR will be offered as a voluntary option to save money as well as help the community during when electric supply is short.

Promotion will include an annual mailing to eligible customers, marketing through key account representatives and technical follow-up from experts in the energy solutions group.

7.2.7 MPOWER Plus

Objective:

The objective of MPOWER Plus to provide additional, SPP qualified, capacity resources, by way of demand response. Since MPOWER includes the potential of a penalty, we view it as likely to be accepted by SPP as reserve capacity.

Description:

This program, which is a modification of the MPOWER program, has the following features:

- Contract term is one year
- Available to customers or an aggregation of customers with a maximum demand of 100kW or more who will commit to a reduction of 50 kW or more.
- Event Period:
  - Mandatory: Noon-10pm
- Event Season: Annual
- Event Advisory: provided day-ahead as a courtesy only
- Event Notice: two hours prior to the beginning of an event
- Event Duration: minimum duration of four hours
- Event frequency: limited to once per day
- Annual Subscription Payment: Established annually based on the value of capacity based on the existing level of capacity margin (reserves) and capacity demand curve
  - Benefit per kW subscribed established each year to reflect avoided costs. Initially $45/kw-yr.

- Subscribed kW: amount of kW reduction committed to by customer below the customer baseline load

- Event Payments:
  - $0.50 per kWh for verified performance
- CBL: Dynamic hourly value that incorporates the most recent historical load, with an optional adjustment for current weather conditions
- Event kWh: the kWh represented by the difference between the actual load during an event and the CBL by hour
- Buy-through: none
- Non-compliance penalty – 1.5 times capacity payment for deficiency kW, defined as the difference between enrolled kW and highest event hour kW measured curtailment. In addition, participation in subsequent year restricted to the deficiency adjusted performance level.

This program differs from the current offerings in a number of important ways that should make it more appealing to customers to participate.

- By shifting to a payment per kWh verified as opposed to kW per event this program offers larger customers the potential benefit increased savings in particular when contrasted to the VLR.
- By shifting to a model with annual subscriptions customers will be able to opt out more easily which reduces a barrier to participation and will increase response.
- Penalty is capacity based.

Target Markets:

This program will be available to commercial and industrial customers who have the ability to shed at least 50 kW. Our expectation is that most subscriptions will come from large industrial and institutional customers.[36]. However, the program will also be available to organizations and business entities that seek to aggregate load. KCP&L has asked about the trade-offs of involving aggregators in its market. A key benefit for KCP&L is that an aggregator can reduce the transaction costs of recruiting smaller loads. Further, the aggregator can take the risk of a potential penalty and, therefore, recruit some customers who might otherwise not subscribe to a program. On the other, hand because they are acting as an intermediary between KCP&L and its customer, KCP&L may need to have a degree of oversight to maintain customer protection. Customers get less if aggregator keeps part do the benefits. KCPL has to settle with these aggregators, what will work every advantage.

Market Strategies:

MPOWER will be promoted in conjunction with VLR where MPOWER To help facilitate response, KCP&L will offer free assessments to interested parties on demand reduction opportunities and an incentive of $50 per kW if they enable demand reduction through the facility's EMS.

Promotion will include an annual mailing to eligible customers, marketing through key account representatives and technical follow-up from experts in the energy solutions group.

7.3 Budget Considerations

KCP&L will have a number of considerations in implementing the portfolio. This subsection is intended to provide some guidance as to the budgetary issues that may pertain. We are describing

[36] UPI does not share that outlook based on other market experience.

them in an overall narrative because this is an integrated offering directed to all classes of customers. The levels-of-funding we describe are consistent with other markets we have seen and are designed to be a reference point to help KCP&L in its decision making process. There are three broad elements that KCP&L will need to address: staffing, IT and billing and marketing costs.

7.3.1 Staffing

As a general matter each of programs will require a project manager and appropriate support staff to:

- Develop and monitor launch schedules
- Coordinate efforts with billing, advertising and customer service.
- Monitor data management
- Provide technical support to other departments
- Report on results and make recommendations.

Since MPOWER and VLR are very closely related a single PM should be designated to manage both. For the pricing programs KCP&L may wish to consider an overall PM supported by project management staff for VPP and RTP.

Since marketing will be key, KCP&L will need to assign a market development leader who will.

- Work with marketing, communications and advertising to develop campaigns
- Track the efficacy of the various promotion efforts
- Coordinate with the company's other programs

Beyond these staff positions there are a wide variety of functions including call centers, telemarketing, and direct mail and, in the case of Optimizer, installation management. These may or may not be staffed internally our outsourced. Outsourcing often offers more rapid deployment, the potential to share risk and the expertise of the supplier. Some utilities, however, prefer to perform these functions using in-house staff as it affords more direct control over activities.

7.3.2 IT and Billing

There are a variety of items that will need to be accounted for in this area. First and foremost is that interval data will be required for RTP, MPOWER, VLR and VPP. As we understand it KCP&L currently has the infrastructure in place to the data. We understand that KCP&L has CellNet meters for over 97% of their customers. For $12.95 per month, KCP&L will be able to read interval data for the specific month of the TOU peak pricing period. KCP&L may wish to visit this cost with the supplier. In addition, communications will be required to notify customers as day ahead pricing and for DR events. The lower cost options for these involve the use of the Internet.

Tools may also be required to help customer analyze various options. We note that KCP&L has a number of tools on its web site under the Energy Analyzer heading. KCP&L may wish to visit with its vendor to determine what the costs may be with these items.

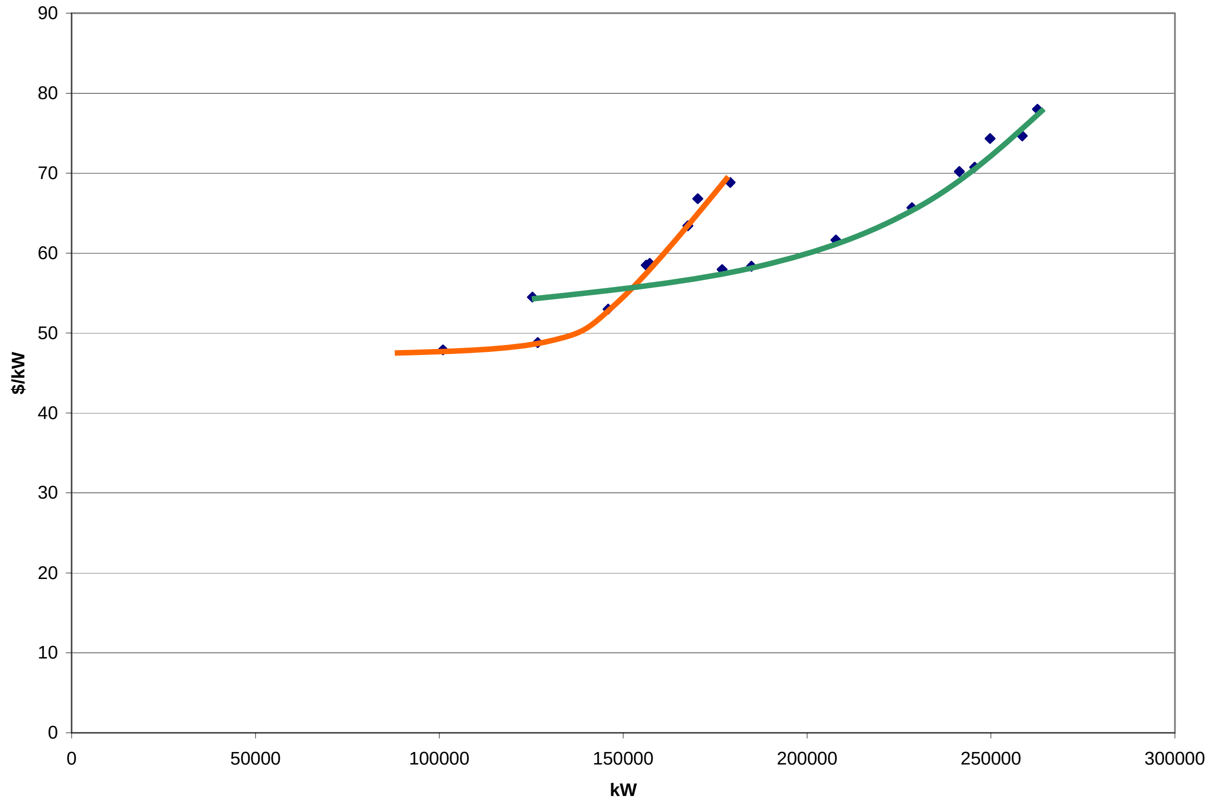
Pertaining to the billing system, with the exception of VPP, all the other rates proposed are modifications to existing rates. This should reduce the complexities of the changes involved. Some utilities outsource their billing for complex invoices such as primary power invoicing. KCP&L may wish to consider that as an option for RTP and VPP.

7.3.3 Marketing Budget

As described in Section 1, there is a balance between marketing expenditures and incentive levels. The incentives need to be high enough to attract a customer; but have diminishing results after a certain point. Likewise marketing cannot make customers buy an unappealing product; but, in many instances a dollar well spent on marketing and education will yield more than an additional dollar spent on incentives.

Figure 7-1 illustrates this point by comparing the results of several simulations. These simulations looked at various allocations of incentive budgets versus marketing budgets. The Y Axis shows the cost per kW for each scenario modeled versus the amount of demand reduction achieved as shown on the X Axis. Some of which are more heavily weighted on incentives – the curve on the right. The other puts more emphasis on the marketing budget. The reader will note that for results in the less than 150 MW range the first set of scenarios cost less per kW reduced. However, beyond that point, then the balance shifts to more expenditure on marketing. Ultimately, KCP&L must determine the supply curve it is seeking. Our analysis indicates to reach the 120 MW region for DR a budget in range of $1 million to $1.2 million for year would be appropriate.

Figure 7- 1 – Comparison of DR Supply Scenarios



8. Summary and Recommendations

This report presented a combination of pricing and demand response programs. In making our recommendations we gathered and analyzed an extensive amount of KCP&L data and employed our judgments and experiences to recommend a balanced portfolio of programs for all its customers. In our view a robust and efficient electricity market needs to include both demand and price response offerings. Each plays a vital and changing role. Further, KCP&L needs to keep in mind that to be successful offerings in this portfolio will need to be fostered vigorously and continuously. While we can estimate, based on experiences in other markets, what KCP&L should achieve, much of the ultimate outcome depends on the quality of your marketing and customer education.

In undertaking our analyzes we employed the economic modeling of behavior to quantify the economic potential for benefits under various market conditions that produces price signals that would induce load changes. Economic potential in the context of price response measures what can be expected in response to prices that reflect the marginal cost of supply for a specified level of customer participation and inherent price elasticity. The achievable potential is represented by the participation rates that are likely to result from a sustained effort to promote participation and foster price response. (We do not distinguish between economic and achievable potential since we only show the results of scenarios that include assumed achievable participation rates) The achievable potential can be increased for any given level of prices by increasing participation and by enhancing the price response capability of participants. Therefore, we used this approach, as opposed to the technical potential models often used for energy efficiency programs because there is a price that all loads would be curtailed but this does not make sense in context of a utility's on-going operations.

Following are recommendations for KCP&L's consideration:

- **Commit to a robust marketing and sales effort**

  As stated above, to be successful these programs must be promoted. For the mass markets, residential and small commercial, this will require continuous communications through direct mailings, its web site and other means to carry the message forward.

- **Include continuous research and evaluation practices as part of the portfolio implementation strategy**

  Achieving the full potential of demand and price response programs requires that KCP&L commit to continuous improvement by learning from experience. The portfolio recommended by the KEMA team is comprised of plans that have performed well elsewhere under apparently similar circumstances. But, there are likely important, and in some cases subtle, differences in customer circumstances and supply conditions that can impact heavily their performance. Only through ongoing evaluation and refinement can KCP&L realize participation and customer responses that achieve the full potential of demand and price response.

- **Reconcile benefits and costs with regulatory finance models and rates.**

  The KEMA team conducted a marginal analysis to quantify the level and distribution of benefits of price and demand response. The results, aligned with final program goals, should be integrated into KCP&L's revenue requirements and financial models to identify the impact on revenues and costs and determine the impacts relative to what excising rates and program are expected to produce. KCP&L will likely find that it requires adjustments in its revenue requirements to be whole from the implementation of these programs. The case for doing so is compelling, given the large benefits that accrue to non-participants.

- **Clarify and achieve complimentary SPP and regulatory treatment of demand response reprocess.**

  M-Power is designed to provide dispatchable loads that 1) substitute for conventional resources in meeting adequacy requirements, and 2) supplement adequacy over and above SPP requirements. SPP approval for substitution M-Power resources will be required to realize benefits, otherwise payments to M-Power participants are redundant, because KCP&L will have to acquire duplicative generation reprocess to fulfill its SPP obligations, and therefore difficult to rationalize. Protocols have been established in PJM, NYISO and ISO-NE, the RTOs that govern reliability in markets that impose a capacity requirement on load-serving entities, that specify how and to what extent curtailable loads can be counted as fulfilling adequacy requirements. KCP&L should being immediately and in earnest to engage SPP in opening proceedings to evaluate the role of demand response in establishing and meeting reliability standards for the market.

- **Identify the benefits to demand response even when generation capacity is surplus**

  Demand response can provide a form of insurance against circumstances where generation capacity that as expected to be available is not. There is also benefit to capacity in excess of adequacy requirements as established by NERC councils. The notion of a demand curve for adequacy resources has been proposed in all three Northeast ISO. NYISO has adopted the concept, which it applies to the procurement of capacity requirements in its deficiency auctions, where generators with unsold qualifying capacity offer it at a specified price and load-serving entities that have not yet meet their capacity requirement enter the auction to do so. The reliability demand curve indicates the value of capacity in excess f what is needed to meet adequacy requirements. Formally establishing a representation of the value of reserves provides KCP&L a way to value not only marginal generation assets are result form the lumpiness of investments in generation units, but also to rationalize payments to customer top provide additional reserves.

- **Establish dispatch protocols for M-Power and Optimizer and consistent protocols for the dispatch of VLR.**

  KCP&L should seek to integrate the dispatch of its capacity programs into its system operations so that events are declared under established conditions that comport with providing value equivalent to or greater than what generation resources would have provided. A starting place would be those adopted elsewhere, but circumstances of the KCP&L load and system supply portfolio will be the determining factors initially. Eventually, these protocols must align with those stipulated by SPP so that demand response resources are counted as providing adequacy capacity. In addition, protocols are needed to direct the use of VLR resources so that they are us cost effectively. Reducing the uncertainty about when events are called is important to promoting participation, and explaining why also contributes substantially, as it helps customers justify participation as good citizenship. Accordingly, the recommended protocols should be conveyed to customers in a way that helps them understand under what conditions and why events are called, so that they can determine to what extent, if any, they can comply with those demands for curtailments. The annual bulletins distributed by NYSERDA provide a useful template to work from.

9. PriceFX Model

The PriceFX Model

UtiliPoint's market price formation model, called PriceFX, quantifies the level and distribution of benefits associated with load changes induced by price response programs. The model has been fully documented elsewhere (Neenan Associates, 2005). The PriceFX structural elements are as follows:

- A **demand model** that uses price elasticity to determine how customers adjust usage to changes in the price they pay for electricity. Customers are segmented into groups that have common price response capabilities so that their collective response can be modeled either for the whole segment, or the part thereof that is assumed to face price changes. Price elasticities are assigned to sub-segments based on their observed intensity of price response in pilots and other market situations where price elasticity was estimated from actual experience. Hourly load shapes are developed for each segment to preserve underlying differences in usage patterns.
- A **supply model** that characterizes hourly day-ahead and real-time price formation on a zonal basis. Historical data are used to estimate a statistical characterization of how zonal loads, generation and reserve availability, weather, congestion, and other factors convolve to determine the price that clears the wholesale electricity market. This provides a baseline from which the impact of load changes on real-time and day-ahead locational marginal prices (LMP) can be measured. In addition, the model estimates the ripple effects, which are 1) reduced bilateral contract hedging prices, 2) lower capacity costs, and 3) social welfare improvements.

Once calibrated, the PriceFX model provides a method to back-cast the implications of demand response. A dynamic pricing program can be postulated and its price elasticity specified. For example, an RTP plan might be proposed whereby customers pay day-ahead LMPs (or prices directly linked to those LMPs) for energy consumed. The demand model calculates the change in usage associated with the supply model's day-ahead hourly prices, or the dynamic prices that are constructed from the hourly LMPs. Those load changes are then incorporated into the supply model which, based on the supply curve's shape, determines by how much LMPs would decline to achieve market-clearing equilibrium. The model then calculates the bill savings associated with load transactions in the market at the time, and the overall change in price volatility over time, and how that would be expected to reduce future hedging costs. Welfare savings, which are calculated using the formulated supply and demand curves, constitute savings associated with more efficient resource utilization since consumers make consumption decision based on marginal supply cost, not some average of all hourly prices.

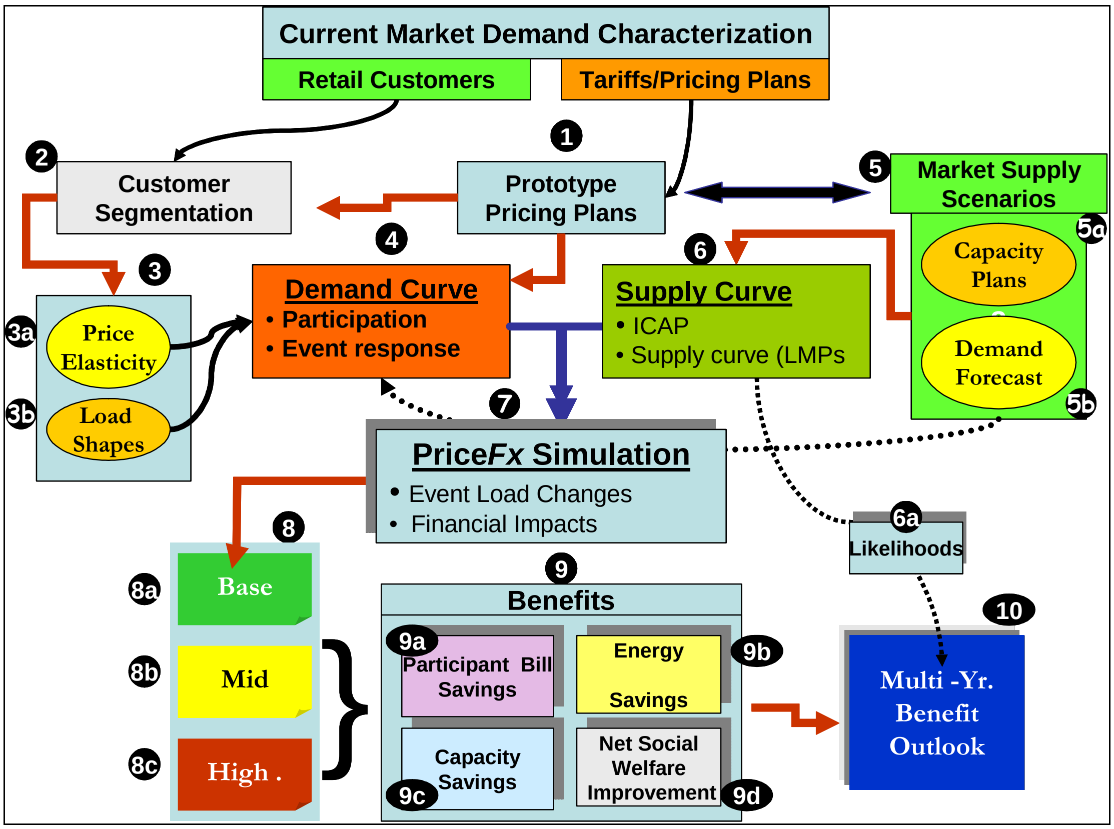
Scenarios are characterizations of demand and supply in the market that diverge from those of the base case. Two classes of scenarios are insightful:

- ***Changes in the character of price response and program participation***. Raising the level of participation or the level of price elasticity provides a measure of the benefits from promoting and building up price response. Such analyses are useful for projecting how the benefits might changes over time as a result of increased customer awareness that raises participation, or higher price response by participants as they gain experience, receive training and support, or adopt technologies that enable a higher response level for any given price change.
- ***Changes in supply fundamentals or the impacts of demand uncertainty***. Changes in the installed capacity of generation influence the level and volatility of LMPs. Scenarios can be built to reflect future market situations, different from those of the base case, to ascertain how the value of price response changes.

The benefits simulated for the base case and each scenario are reported in a standardized form to facilitate examining changes across scenarios. Financial benefits (bill savings) are separated into those that inure to participants and those that other customers or entities realize. Societal benefits are reported as collective monetary benefits. Reductions in coincident and non-coincident demands complete the characterization of the impacts of price response. The level of these benefits depends on participation rates in pricing programs. Thus, establishing the economic potential requires specifying participation, which could be at the customer's election, including the current rate as an option, or mandated with each customer group designated a dynamic rate.

Figure 9-1 illustrates the structure of the PriceFX modeling platform. It illustrates how data flows into the PriceFX simulation model, which characterizes price formation in an electricity market. Simulations can be performed over historic periods to imply the value of demand response actions already undertaken, or in a prospective mode, to estimate the impacts of programs that are contemplated or already in place. The model conducts an hourly or daily simulation of supply and demand and produces a discrete outcome for any data set, which includes market characterization in the form of 8,760 hourly LMPs or an alternative representation of marginal supply costs (such as utility dispatch costs with a scarcity pricing element). Supply scenarios can be created to characterize the distribution of outcomes to reveal the value of demand and price response under conditions that produce especially severe and proportionally greater adverse consequences, and therefore should be considered in setting the value of demand response.

The project task descriptions that follow provide a detailed discussion of how each data and model element will be developed.


Current Market Demand Characterization
Retail Customers
Tariffs/Pricing Plans
1
2
Customer Segmentation
Prototype Pricing Plans
5
Market Supply Scenarios
4
3
6
5a
Capacity Plans
Demand Curve
• Participation
• Event response
Supply Curve
• ICAP
• Supply curve (LMPs
3a
Price Elasticity
3b
Load Shapes
Demand Forecast
5b
7
PriceFx Simulation
• Event Load Changes
• Financial Impacts
6a
Likelihoods
8
8a
Base
8b
Mid
8c
High .
9
Benefits
9a
Participant Bill Savings
Energy Savings
9b
Capacity Savings
9c
Net Social Welfare Improvement
9d
10
Multi -Yr. Benefit Outlook

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Goldman, C., Hopper, N., Bharvirkar, R., Neenan, B., Boisvert, R., Cappers, P., Pratt, D., Butkins, K. August 2005. Customer Strategies for Responding to Day-Ahead Hourly Electricity Prices. Demand Response Research Center. Lawrence Berkeley National Laboratory Report No. LBNL-57128. Available at http://eetd.lbl.gov/EA/EMP/drlm-pubs.html

Neenan Associates. February 2004. A Study of NYISO 2003 PRL Program Performance. Available at http://www.nyiso.com/public/products/demand_response/index.jsp

Neenan Associates. December 2005. Improving Linkages between Wholesale and Retail Markets through Dynamic Retail Pricing: Preliminary Results. Report prepared for New England ISO. Available at www.ISO-NE.com.

Appendix A

Summary of Research of Price Response Reports

The following reports were reviewed to identify any information regarding the distribution of price elasticities or information regarding varying price elasticities.

1. Commercial/industrial customer response to time-of-use electricity prices: some experimental results, Rand Journal of Economics Vol. 16, No 3, Autumn 1985, Dennis J. Aigner and Joseph G. Hirschberg. Substitution elasticities by size of customer.
2. Real-Time Pricing of Electricity for Residential Customers: Econometric Analysis of an Experiment, Journal of Applied Econometrics, Vol. 10, S171-S191 (1995), Christophe Aubin, Denis Fougere, Emmanuel Husson, Marc Ivaldi. Substitution elasticities (mean and std dev) for residential customers in France.
3. Residential TOU Price Response in the Presence of Interactive Communication Equipment, Steven Braithwait, Chapter XX. Substitution elasticities for residential customers (point estimates only).
4. The neoclassical model of consumer demand with identically priced commodities: an application to time-of-use electricity pricing, Rand Journal of Economics, Vol. 18, No. 4, Winter 1987, Douglas Caves, Laurits Christensen, Joseph Herriges. Substitution elasticities for residential basic, residential with AC, and residential with electric heat.
5. A Comparison of Different Methodologies in a case study of residential tou electricity pricing, cost-Benefit Analysis, Douglas Caves, Laurits Christensen, Philip Schoech, Wallace Hendricks, Journal of Econometrics 26 (1984). Nothing relevant.
6. Econometric Analysis of residential TOU electricity pricing experiments, Douglas Caves, Laurits Christensen, Journal of Econometrics 14 (1980). Nothing relevant.

7. Residential Substitution of Off-peak for Peak Electricity Usage under tou pricing, Douglas Caves, Laurits Christensen, The Electricity Journal Vol. 1 No. 2 (1980). Substitution elasticities for residential customer by size.

8. Consistency of Residential Customer Response in tou electricity pricing experiments,, Douglas Caves, Laurits Christensen, Joseph Herriges, Journal of Econometrics 26 (1984). Nothing relevant.

9. The Value of Dynamic Pricing in Mass Markets, Ahmad Faruqui, Stephen George, Elsevier Science, Inc. (July 2002). Nothing relevant.

10. Quantifying Customer Response to Dynamic Pricing, Ahmad Faruqui, Stephen George, Elsevier Science, Inc. (May 2005). Nothing relevant.

11. Time-of-use prices and electricity demand: allowing for selection bias in experimental data, Rand Journal of Economics Vol. 28, No. 0, 1997, John C. Ham, Dean C. Mountain, and M.W. Luke Chan. Nothing relevant.

12. The response of industrial customers to electric rates based on dynamic marginal costs, The Review of Economics and Statistics, Vol. 75, Issue No. 3, August 1993, Joseph Herriges, S. Mostafa Baladi, Douglas W. Caves, Bernard F. Neenan. Nothing relevant.

13. Customer response to Real-Time Pricing in Great Britain, 1994, Kathy King, Peter Shatrawka. Nothing relevant.

14. The Economics of Real-Time and TOU Pricing for Residential Customers, updated version of paper presented at the Third Annual International Distribution and Demand Side Management Conference , June 2001,Chris S. King, American Energy Institute. Nothing relevant.

15. Peak and Off-peak Industrial Demand for Electricity: The Hopkinson Rate in Ontario, Canada, Dean C. Mountain, Cheng Hsiao, The Energy Journal Vol. 7 No. 1 (1986). Substitution elasticities by a broad industry definition for a demand and energy TOU rate.

16. Real-Time Pricing – Supplanted by Price- Risk Derivatives? Mike O'Sheasy, Public Utilities Fortnightly, March 1, 1997. Nothing relevant.

17. Estimating the Customer-Level Demand for Electricity under Real-Time Market Prices, National Bureau of Economic Research, Working Paper 8213, April 2001,Robert H. Patrick, Frank A. Wolak. UK markets - Nothing relevant.

18. Industrial Response to Real-Time Prices for Electricity: Short-Run and Long Run, JEL Classification: L9 Industry Studies: Transportation and Utilities, May 2000, Peter Schwarz, Thomas N. Taylor, Matthew Birmingham, Shana L. Dardan. Transmission vs. Distribution voltage industrial customer price elasticities.

19. Impact Evaluation of the California Statewide Pricing Pilot, Charles Rivers Associates, March 16, 2005, Final Report. Has substitution elasticities by program (CPP, TOU, VPP), by customer size, by day-type and season.

20. Evaluation of the 2005 Energy-Smart Pricing Plan^{SM}, Summit Blue Consulting, August 1, 2006, Final Report. Has substitution elasticities for residential with appliance contribution to elasticity.

21. Advance Notice of Real-Time Electricity Prices, Atlantic Economic Journal, Dec 2000, Thomas N. Taylor, Peter Schwarz. Nothing Relevant.

22. 24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience, Journal of Regulatory Economics, 27:3 235-262, 2005, Thomas N. Taylor, Peter Schwarz, James E. Cochell. Price elasticities estimates by industrial classification.

23. The long-run effects of a time-of-use demand charge, Rand Journal of Economics, Vol. 21, No. 3, Autumn 1990, Thomas N. Taylor, Peter Schwarz. Nothing Relevant.