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Customer Load Participation in Wholesale Markets: Summer 2001 Results, Lessons Learned and "Best Practices"

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Introduction

The restructuring of the U.S. electricity markets has created new opportunities for customers to partner with load serving entities such as utilities or retail energy suppliers in order to curtail or alter their demand in response to either electric system reliability needs or high prices. Although the benefits of allowing customers to manage their loads in response to system conditions or wholesale market prices are potentially large, there are numerous challenges to creating workable price-responsive load programs. Utilities have operated load management programs in a completely regulated environment for many years. With restructuring, demand response (DR) or price-responsive load (PRL) programs are increasingly designed and administered by different entities (e.g., ISOs), involve new market participants (e.g., retail suppliers, curtailment service providers), and are triggered by economic considerations as well as electric system reliability conditions.

Lawrence Berkeley National Laboratory, with funding from the Department of Energy Office of Power Technologies, has been examining the potential role of customer load participation in wholesale and retail electricity markets. This study summarizes key findings from an ongoing research project that includes case studies of approximately thirty demand response programs offered by twenty one program administrators which include investor-owned utilities, ISOs, and a federal power marketing authority (see Table 1).[1] The thirty programs surveyed encompass an array of program types: innovative demand bidding programs as well as several more traditional interruptible load management programs.[2] We focus on the market potential of price-responsive load programs, summarize program experience and lessons learned, and identify examples of current "best practices." Case studies were developed based on phone interviews with program managers, review of program information materials, and evaluation studies. The survey covered key program elements such as target markets, market segmentation, and participation results; pricing schemes; dispatch and coordination; measurement, verification, and settlement; enabling technologies; and operational results, where available.

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[1] Earlier work on demand response programs is summarized in Heffner, G. and C Goldman. "Demand Response Programs – An Emerging Resource for Competitive Electricity Markets," 2001 International Energy Program Evaluation Conference, August 21-24, 2001, Salt Lake City, Utah.
[2] A number of programs offered distinct options, where, in one option, participants could be requested to curtail due to system reliability considerations and in the second option, participants could offer to curtail loads in response to wholesale electricity price signals. In our analysis, these options were treated as separate programs in order to draw key distinctions.

Table 1: Case Study Programs and Program Administrators

Administrator(s)	Organization Type	Programs	Reference Code*
AES NewEnergy	Retail Electricity Service Provider	Incremental Incentive Curtailment Program	A
Ameren	Investor-Owned Utility	Customer Energy Exchange	B
Baltimore Gas and Electric	Investor-Owned Utility	Load Response Program Option 1 Load Response Program Option 2 Rider 14 Emergency Generation and Rider 16 Curtailable Service	C2 C3 C4
Bonneville Power Authority	Federal Power Marketing Authority	Demand Exchange Pilot Program	D
Cal ISO	Independent System Operator	Demand Relief Program, Discretionary Load Curtailment Program	E1 E2
Cinergy	Investor-Owned Utility	Power Share Program	F
Commonwealth Edison	Investor-Owned Utility	Voluntary Load Reduction Program	G
Dominion Virginia Power	Investor-Owned Utility	Economic Load Curtailment Program	H
ISO-NE	Independent System Operator	Load Response Program – Class 1 Load Response Program – Class 2	I1 I2
Kansas City Power and Light	Investor-Owned Utility	Peak Load Curtailment Credit, Voluntary Load Reduction Program	J1 J2
Nevada Power, Sierra Pacific Power	Investor-Owned Utility	Optional Curtailment Program for Large Customers	K
NYISO	Independent System Operator	Day Ahead Demand Response Program, Emergency Demand Response Program	L1 L2
Pacific Gas and Electric, Southern California Edison, San Diego Gas and Electric	Investor-Owned Utility	Demand Bidding Program, Interruptible Programs, Optional Binding Mandatory Curtailment Program	N1 N2 N3
PacifiCorp	Investor-Owned Utility	Energy Exchange Program,	O1
PJM ISO	Independent System Operator	Load Response Pilot Program – Economic Load Response Pilot Program – Emergency	P1 P2
Portland General	Investor-Owned Utility	Demand Buy Back Program	Q
San Diego Gas and Electric	Investor-Owned Utility	Regional Blackout Reduction Program	R
Southern California Edison	Investor-Owned Utility	Direct Load Control Programs	S
Wabash Valley Power Association	Electricity Cooperative	Customer Payback Plan	T
Xcel Energy	Investor-Owned Utility	Electric Reduction Savings Program, Peak Day Partner Program	U1 U2

***** Reference codes are used to refer to programs in the figures throughout the paper.

Key Findings

(1) Price-responsive load (PRL) programs and other DSM/energy efficiency programs played an important role in mitigating electrical system emergencies in several regions of the country during Summer 2001

- The week of August 4, 2001 was a particularly hot period throughout the East Coast. During this period, price-responsive load and other programs reduced system peak demands by 3-6% and helped avert potential system emergencies (see Table 2). Policymakers should ensure effective coordination and deployment of both PRL programs, which focus on short-term demand response, and energy efficiency programs, which can reduce long-term demand growth and can also play a role in addressing system reliability issues.

Table 2: Summer 2001 Contributions of Price-Responsive Load and Other DSM Programs.[3]

ISO	System Peak (MW)	Interruptible Load	Curtailable Load	Other DSM	Total DSM	DSM as % of System Peak
PJM	52,977	2,000	70	-	2,070	3.9%
NY ISO	29,983	-	500	365	865	2.9%
ISO NE	25,675	-	65	1,522	1,587	6.2%

(2) Overall, Summer 2001 was a relatively low-activity year for price-responsive load programs – except in the Northeast.

- Programs are grouped into two broad categories: "reliability-based" programs that operate in response to system contingencies and "market-based" programs that are triggered by wholesale market prices. Of the 30 programs surveyed, only a handful operated more than ten times (see Figure 1). Fourteen of the programs operated just once or not at all. The proximate cause for the generally low level of activity was the limited number of reliability events and the relatively low wholesale electricity market prices. However, despite their infrequent operation, several programs played a critical role in mitigating regional system contingency events and provided significant economic and system reliability benefits.

[3] Based on Xenergy/KEMA Consulting. "Demand Response During Market Transition: Lessons of Summer 2001," Presentation to USDOE Office of Power Technology, Francis Cummings, Nov. 8, 2001.

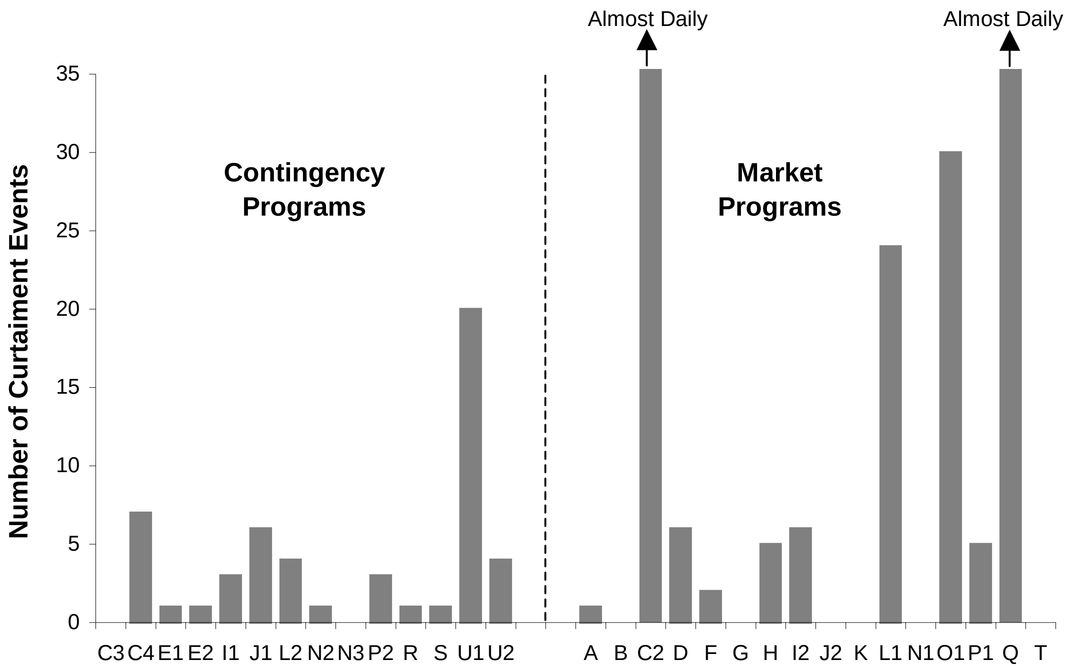

Figure 1: Number of Events or Event Days in Summer 2001.

"Contingency" DR Programs

- Record setting peaks occurred throughout New England and the Mid-Atlantic regions during the week of August 7. The Contingency programs of NYISO, PJM, ISO-NE, and BG&E were all operated during this period, providing critical relief to the strained grid. The NYISO Emergency Demand Response Program (EDRP) provided an average demand response of 425 MW on four occasions, equivalent to approximately 25% of the total system reserve requirement. An analysis of the program impact estimates that, for *a single hour* during this period, the EDRP likely provided reliability benefits of between $870,000 and $3,484,000. The program is estimated to have resulted in an additional $16.8 million dollars in collateral benefits, associated with reductions in electricity prices and volatility, over the duration of the summer.[4]

- The big surprise was California, with only one contingency event throughout the entire summer, despite NERC's predictions of more than 260 hours of rolling blackouts. A major contributing factor was the extensive level of peak demand reduction (on the order of 10%) resulting from a combination of energy efficiency and demand response programs, voluntary initiatives, increases in electricity rates, and widespread media attention on the State's electricity crisis. On the single curtailment day, approximately 800 MW was curtailed, the majority of which is

[4] Neenan Associates (2002), NYISO PRL Program Evaluation: Executive Summary.

attributable to the interruptible and direct load control programs of Southern California Edison.

- Xcel's Electric Reduction Savings Program (U1) also operated quite frequently in Summer 2001, with 20 events. However, the program was not generally operated in response to explicit reliability conditions (e.g., generation shortages or transmission constraints), but was, instead, operated so that Xcel could avoid exceeding MAPP authorization levels and paying the associated fines.

DR "Market" Programs

- In the Pacific Northwest, several day-of and day-ahead bidding programs had high activity levels during Winter and Spring 2001, driven by high wholesale electricity prices. However, during Summer 2001, there was a dramatic drop-off in demand-response program activity, apparently driven largely by the impacts of FERC price mitigation measures. Many programs base the incentive for participants on roughly a 50/50 sharing of the avoided wholesale purchase cost. With the soft price cap of approximately $92/MWh, the incentive available for participants dropped down into the $40-50/MWh range, which is well below the level at which most end-users would be willing to bid in load. For example, the day-ahead bidding component to Portland General Electric's (PGE) Demand Buy Back Program (Q), which had been active up until that point, received no bids once the price caps were implemented. However, PGE's program did provide curtailments on an almost daily basis during the summer through "term" events that had been procured prior to the drop in wholesale prices (i.e., demand buy-back initiatives). In California, participants submitted bids for the Demand Bidding Program regularly throughout the summer, but none were accepted by the California Department of Water Resources because prices remained below the minimum available bid price of $100/MWh.

- In the Midwest, program activity was low as a result of the soft wholesale electricity prices throughout the region. Wabash Valley Power Authority's Customer Payback Plan was originally offered with a $200/MWh strike price, but prices remained well below this level, and the strike price was dropped to $50/MWh.

- During the August heat wave on the East Coast, real time electricity prices reached $1000/MWh in both ISO-NE and NYISO markets, and more than $900/MWh in PJM's region. All three programs provided load relief during these periods, although the level of load curtailment was generally small. The NYISO's Day Ahead Demand Response Program (L1) was available for bidding on a continual basis and operated throughout the summer on 24 occasions.

(3) *Load relief from DR Market programs is typically much lower and often less predictable than load relief from Contingency programs.*

The average potential curtailable load for DR Contingency programs and DR Market programs were similar (see Table 3). However, the two program types differed markedly in the load curtailment actually delivered in our sample of DR programs. When system reliability events occurred, actual load curtailments from DR Contingency programs were, on average, about 62% of the potential curtailable load from participating customers. Tracking this type of information will help ISOs and utilities determine the extent to which they can rely on demand response programs during system emergencies. In contrast, the average curtailed load in our sample of DR market programs was, on average, about 17% of the potential curtailable load. Several factors contribute to this phenomenon.

Table 3: Average Performance Characteristics of Contingency and Market Programs with Curtailment Events in 2001.

Program Type	Number of Programs	Average Potential Curtailable Load (MW)	Actual Average Curtailed Load (MW)	Actual/Potential
Contingency	8	158	84	62%
Market	10	204	21	17%

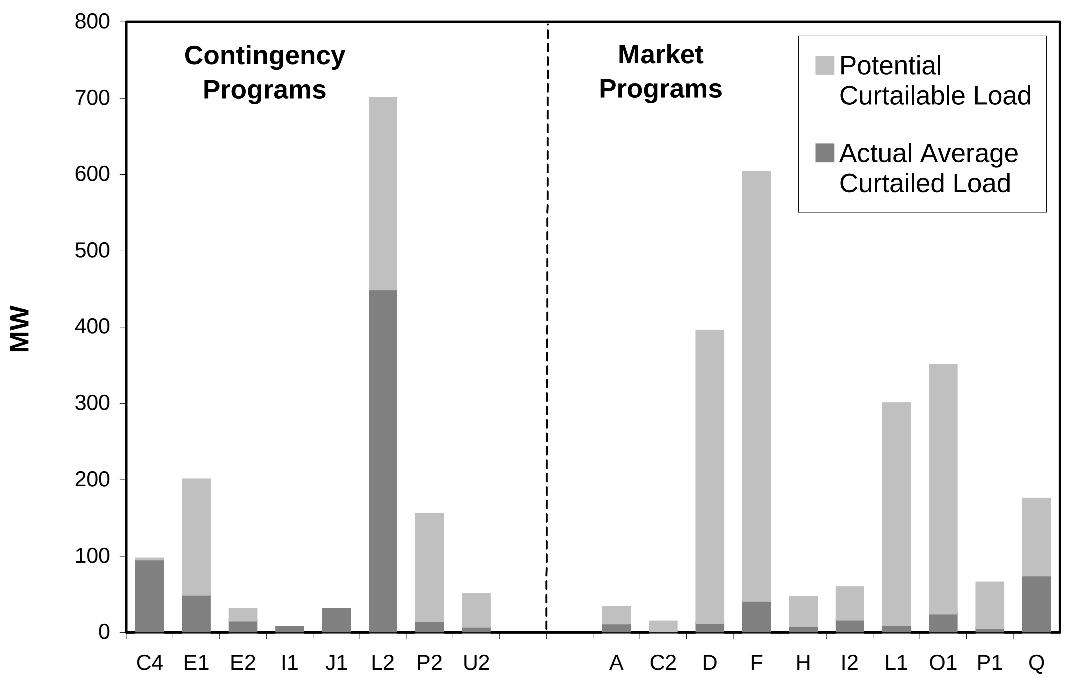

Figure 2: Comparison of Potential Curtailable Load and Actual Average Curtailed Load in Contingency and Market Programs. Only programs with curtailment events in Summer 2001 included.

- *Incentive Mechanisms*. The incentive mechanism encompasses both the payment for curtailment and the penalty for non-compliance. Contingency programs are generally “Call-type” programs, in which participants agree ahead of time to provide a specific level of curtailable load upon notification, and in many cases are subject to non-compliance penalties if they fail to meet their commitment. About 50% of the

Contingency programs in our sample levied some form of financial penalty.[5] For example, in Kansas City Light and Power's Peak Load Curtailment Program (J1), participants performed at 30% *above* their committed level in aggregate, reportedly in order to avoid non-compliance penalties. Market programs, on the other hand, are generally "Quote-type" programs, where customer participation is "voluntary."[6] Participants are paid solely on the basis of MWh curtailed, and decide on their level of load curtailment on a case-by-case basis, without the risk of being penalized. The decision to curtail is based on a comparison of the curtailment payment to their outage costs, and because both will tend to vary considerably, participation in Quote-type Market programs is highly volatile. Over the long term, accurately forecasting/predicting the level of demand response in Quote-type programs will be critical for policymakers in order to assess the ability of these programs to mitigate high wholesale market prices.

- *Definition of Potential Curtailable Load*. In Contingency programs, participants typically pledge a specific level of curtailable load when they sign up for the program, providing program administrators with a relatively clear measure of the potential curtailable load for the program. In Quote-type Market programs, however, there is no analogous measure of the potential curtailable load of the program. Some program administrators use each participant's peak or average demand as their potential curtailable load, which generally overstates the load reductions that participants are willing to provide, thereby contributing to the apparent low performance level of these programs. In this case, the difference in performance level, therefore, has more to do with unrealistic expectations than with poor performance. Alternatively, some administrators of Market programs work directly with participants to identify specific load curtailment strategies. This approach can provide a more realistic and justifiable measure for estimating the potential curtailable load of a program.

- *Low Wholesale Electricity Prices*. Since the incentive for participation in Market programs is generally tied to wholesale electricity prices, and wholesale prices were generally low in 2001, participation in these programs was limited. Often, only several participants in a program actively bid, with a higher level of participation on days with exceptionally high prices. When prices did spike, it was often in concert with a reliability event, and many customers who simultaneously participated in Contingency programs had their load curtailment resources already committed.

[5] NYISO's Emergency Demand Response Program (EDRP), which achieved an average load reduction of 450 MW out of a potential curtailable load of 700 MW, did not penalize participants for non-compliance. However, many of the participants in EDRP simultaneously participated as Special Case Resources in NYISO's Installed Capacity Program, which did include non-compliance penalties, and it is unclear at this time to what extent this may have played a role in the relatively high level of performance of the EDRP.
[6] Among our case studies, Cinergy's PowerShare Call Option, Wabash Valley Power Authority's Customer Payback Plan, and Commonwealth Edison's Voluntary Load Reduction Program were the only instances of Call-type Market programs. All of the remaining 17 Market program included in our survey were Quote-type programs.

(4) *Backup Generators (BUGs) were a favorite demand reduction strategy among customers, but environmental impacts are a major concern in some regions and must be addressed in order to realize the full potential of this strategy for customers.*

Emergency Backup Generators (BUGs) were a particularly popular strategy used by many customers to participate in DR programs. From the customer's perspective, BUGs provide a predictable level of load reduction; their operation can be initiated quickly and with minimal disruption to the end-user's normal operations; and, in many cases, they are already in place, minimizing any additional capital expenses required for participation in a DR program. However, many BUGs are diesel-powered and pollute at a significantly higher level than typical central station power plants and their use is typically restricted to a relatively few number of hours per year (e.g., 100-500 hours) by the local air quality control district.

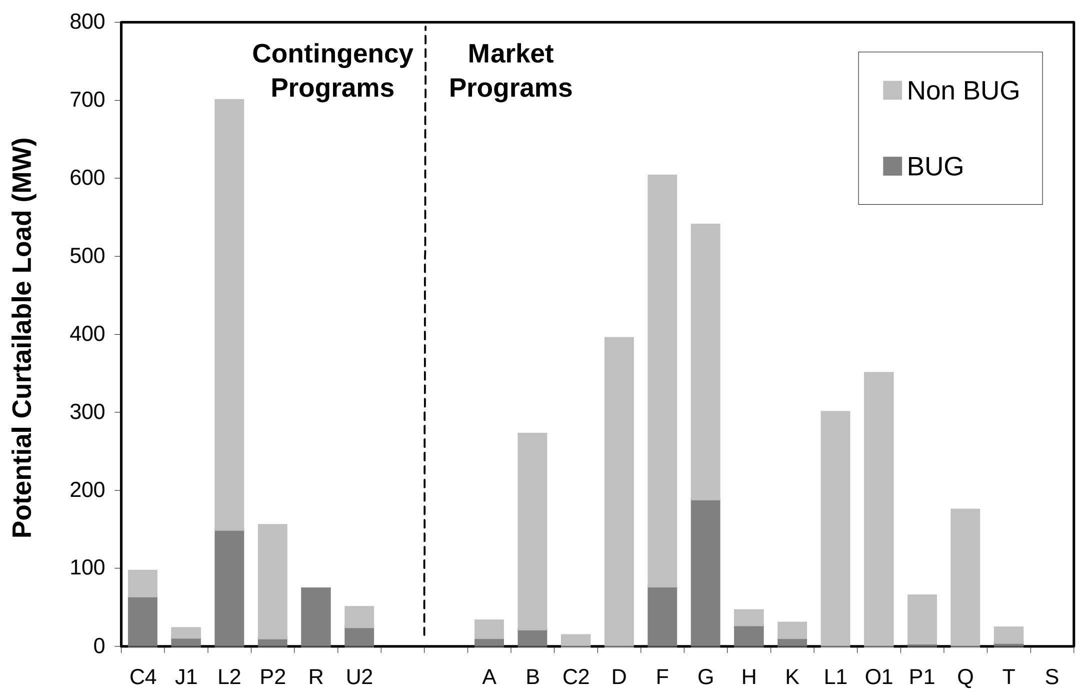

Figure 3: The role of backup generation (BUG) in demand response programs.

- Among programs in our sample, BUGs represent approximately 17% of the total potential curtailable load.[7] BUGs tended to be more heavily used in Contingency programs, representing 31% of potential load reduction compared to 12% in Market programs.

[7] Several programs in our sample did not provide an estimate for the percent contribution from BUGs, although they did indicate that a significant portion of their potential curtailable load was associated with BUGs. Since these programs were not included in the calculation, it is likely that the overall contribution of BUGs among our sample was in the 20-25% range.

- Use of BUGs may have been even more pronounced but some states precluded or limited their use in DR programs. For example, BUGs were not allowed in BPA's Demand Exchange Program (D), PacifiCorp's Energy Exchange Program (O1) or Portland General Electric's Demand Buy Back Program (Q). In Dominion Virginia Power's Economic Load Curtailment Program (H), participation in northern Virginia was reportedly limited due to the more stringent air pollution requirements in that region. Because of the potentially significant reliability benefit that BUGs can provide, states may wish to consider allowing their use for a limited number of hours (e.g., 100-200) per year for DR Contingency programs. *We recommend that other states seriously consider the approach used in New York: allowing back-up generators to participate in Contingency DR programs, provide incentives to encourage relatively "clean" back-up generation, and limit use to non-diesel BUGs in Market DR programs.*

- Novel approaches can be taken to offset the environmental impact of BUGs, while taking advantage of their value as a physical and financial hedge. For example, the New York State Research and Development Agency (NYSERDA) provided funding for enabling technology, including BUGs, in order to facilitate participation in the NYISO's demand response programs. To mitigate the environmental impact, NYSERDA purchased and retired NO_x allowances equal to twice the total calculated NO_x emissions associated with use of these BUGs in the NYISO program.

(5) New program marketing strategies and enabling technologies will be necessary to expand customer participation, particularly in "market-driven" DR programs.

- The DR programs in our sample varied considerably in customer participation levels in the targeted markets (see Figure 4). Nine of 15 programs reported customer participation levels that were greater that 25% of the target market. These market penetration rates are encouraging in terms of number of customers enrolled in programs. Moreover, many utilities and ISO programs have successfully enrolled several hundreds MWs of potential curtailable load enrolled in "contingency" DR programs. However, actual load curtailments offered in DR market programs are still rather low. Thus, the challenge is to increase actual customer participation rates and/or enrollment levels, particularly in "market-driven" DR programs, if policymakers and program administrators are to achieve the goals of actually mitigating high wholesale market prices (and generator market power) and increasing "demand elasticity" of aggregate customer demand. This raises the following questions: to what extent has the current target market been "tapped" and how can program participation be increased?

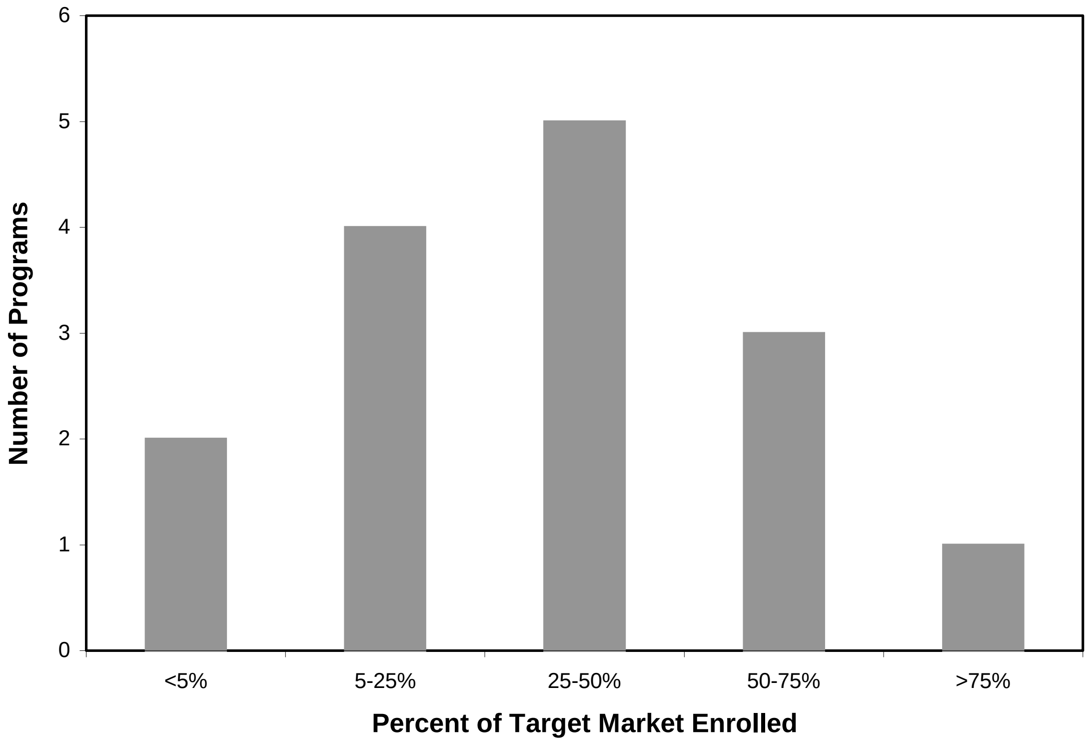

Figure 4: Distribution in the Estimated Percent of Target Market Enrolled of Each Program.

- In our program sample, about 50% of the participants are industrial customers (e.g., steel mills, pulp and paper mills, cement plants), ~25% are commercial customers (e.g., office and retail), with the remainder consisting primarily of institutional and manufacturing customers (see Figure 5). Many industrial customers have the ability to shift or curtail load for a period of time, and still maintain their basic operations. Moreover, industrial customers have been active participants in "legacy" load management programs such as interruptible rates and are therefore already acquainted with load curtailment protocols, requirements, and settlement. Attracting greater participation from commercial and institutional customers will be critical if DR programs are to achieve their full potential.

- In terms of customer size, about 70% of program participants are large or very large customers (see Figure 6). In many cases, this is the direct result of program design decisions to limit participation to customers above some minimum size or who can curtail above some minimum level of demand. Some programs require load curtailments on the scale of 500 kW or even 1 MW. Most DR programs in our sample required curtailments of at least 100 kW. These minimum customer load curtailment requirements severely limit participation by medium-sized C/I customers without a large percentage of discretionary load. These customers represent a significant fraction of the remaining market potential; policymakers and program administrators will have to seriously consider aggregation schemes or lower load curtailment thresholds if they hope to tap these customer market segments.

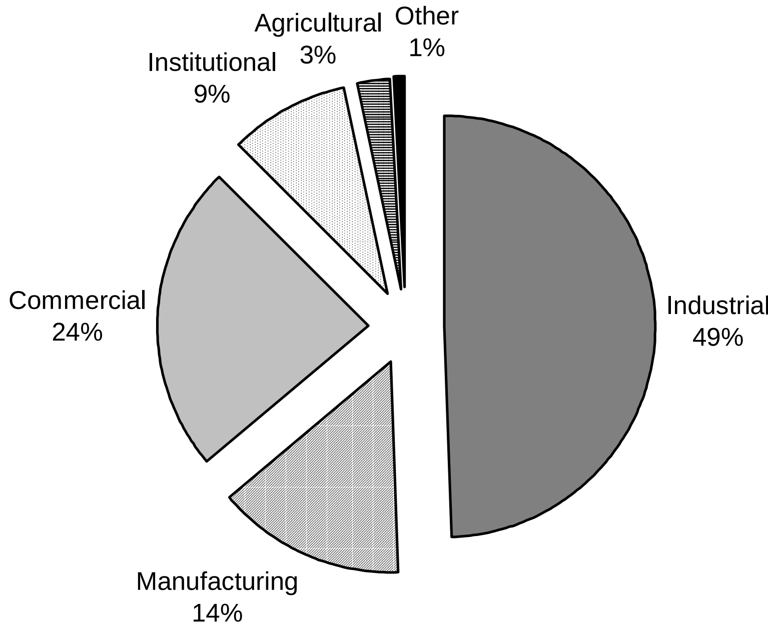

Figure 5: Participation in Demand Response Programs by Customer Class, Average Values (n=16).

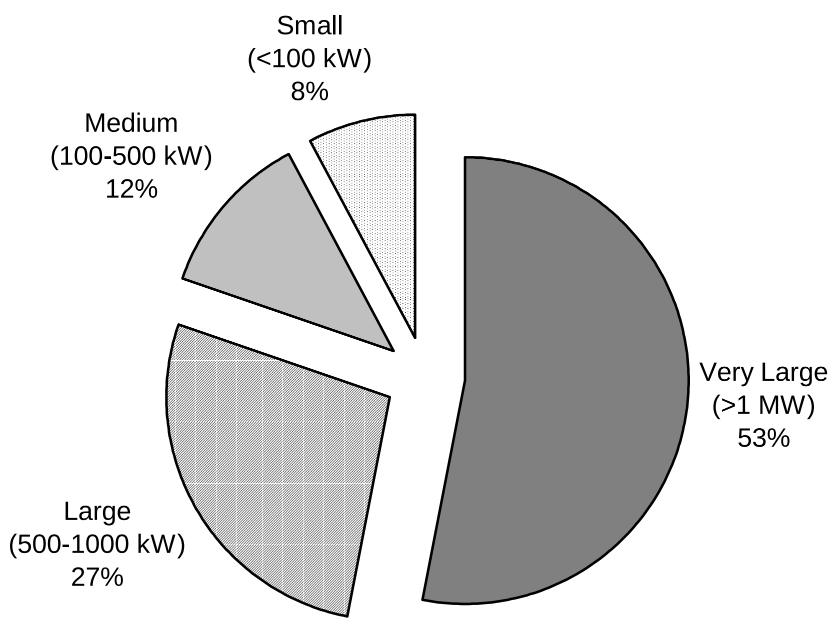

Figure 6: Participation in Demand Response Programs by Customer Size, Average Values (n=11).

- Lower levels of participation by small and medium customers are also often indirectly related to program design decisions regarding the complexity of participation and the associated capital and transactional costs. For example, interval meters are an essential component to the measurement and verification process in most programs. However, these meters are generally not already in place at medium and small customer facilities. In both New York and California, financial incentives for interval meters with two-way communications software along with other enabling technologies has been made available to facilitate customer participation in DR programs, particularly by medium-sized C/I customers (e.g., 200-500 kW peak demand). Policymakers in other states and regions may want to consider such strategies in order to address participation barriers for small and medium-sized customers.

- With a greater level of participation by smaller customers comes the potential for a significantly larger administrative burden. New entrants into the industry such as retail electricity providers, curtailment service providers, and other aggregators may be required to manage the expanded pool of participants. Advanced technologies and communications schemes will also likely be required for mediating the notification and response of curtailment opportunities, collecting and processing data, automating load curtailments, and providing participants with the ability to monitor the performance of their load curtailments.

(6) Customers get confused by multiple program offerings and discouraged by programs with complex rules/requirements and lengthy financial settlement processes

Our case studies of DR programs also provide examples where myriad and multiple program offerings confused customers. In California, the investor-owned utilities, under CPUC direction, implemented an array of demand-response programs (e.g., Demand Bidding Program, Base Interruptible Program, Optional Binding Mandatory Curtailment program, Scheduled Load Reduction Program, Direct Load Control, Rolling Blackout Reduction Program) and the CAISO administered an emergency Demand Relief Program. Most of the new programs were rolled out during the Summer 2001 electricity crisis and program rules kept changing for several programs. Customers were confused by the multiple program offerings and revisions as well as coordination issues between utility and ISO program offerings. Program managers in several programs reported that financial settlement processes were quite lengthy (e.g., >90 days), and that this was a source of customer complaints.

<u>Best Practices</u>

(1) Effective coordination between ISO and utility programs: NYISO EDRP and DADRP Program

Every region where ISOs have formed – PJM, New England, California, and New York – has had to confront a set of institutional issues relating to administration and implementation of DR programs. Issues include: (1) coordination and relationship of

ISO programs to existing and proposed utility load management and DR programs: should there be standardized statewide or region-wide programs? Should utilities take lead in designing DR programs for the retail market? (2) role of the ISO with end users– should they deal with customers directly or only through intermediaries? (3) what entities should be eligible to participate in ISO DR programs – utilities, retail energy suppliers, curtailment service providers, customers directly?

New York appears to have done a good job at working through these issues in a way that allowed for effective program implementation. As Summer 2001 approached, New York faced potential system reliability problems which prompted the Public Service Commission, utilities, and NYISO to develop and deploy several demand response programs on an accelerated basis. The stakeholder input and decision-making processes used in New York (e.g., NYISO Price-Responsive Load Working Group, the PSC proceedings) resulted in two statewide demand response programs administered by the NYISO with the utilities acting as aggregators of their retail customer load which fed into the NYISO program.

Specifically, the NYISO operated the Emergency Demand Response Program (EDRP) and the Day-Ahead Demand Response Program (DADRP). The EDRP is operated only during an Operating Reserve Deficiency or Major Emergency notification issued by the NYISO. It is a Call-type program but is voluntary in that there are no penalties, and payment is based on the performance of a participant in each hour of a curtailment event. The DADRP is a fully voluntary Quote-type program in which participants are given an opportunity to bid load curtailments into the wholesale market on any occasion.

End-users participate in the programs through an intermediate aggregator, such as a utility, retail electricity provider, or curtailment service provider. All six of New York's investor owned utilities participated as aggregators in the NYISO programs. The aggregators were responsible for recruiting end-user participation in the programs under their own product offering, and coordinating the response during curtailment events. Payment and reconciliation occurred between the NYISO and the aggregators, with separate terms negotiated between the aggregators and end-users. The partnerships enabled retail customers to directly participate in wholesale markets while limiting the transactional burden on the ISO.

(2) Suite of DR programs tailored to customer needs with high participation: Cinergy

Cinergy has consolidated all of its demand management programs into one umbrella offering -- the ***PowerShare Pricing Program***. Cinergy's program is one of the largest programs in the U.S. and has achieved very high participation rates: over 90% of Cinergy's 312 large C/I customers were participating in one or more of the PowerShare options. Cinergy estimates of curtailable load range from 440-600 MW, although the program was not operated during 2000 and 2001. The program draws from industrial and commercial customers and attracts a variety of customer sizes – from 100 kW to over 1 MW.

The program has two major options – the Call Option and the Quote Option. Participants in the Call Option select a Strike Price, from among a pre-specified set of choices, based upon their own estimate of the costs of complying with curtailments. When the day-ahead market prices are projected to be greater than the Strike Prices, Cinergy can "call" the option. Customers have several choices in how they identify their curtailable load block: they can specify a Firm Load Level, identify a generator to operate, pledge a specific end use or process to shut down, or pledge a fixed reduction in their pro forma load. Customers may also select from among several levels of curtailment frequency and duration. These various options are packaged into discrete product offerings: the Core Offering, PowerShare Basic, PowerShare Lite, and PowerShare DG. The Quote Option is less complex and offers customers a no-risk proposition. Participants pre-specify only the type of load block (load reduction from a pro forma load shape or generator to be switched on) and a Strike Price below which they are not interested in participating. Cinergy provides price quotes for the same day via the program web site, and interested customers must respond with an estimate of voluntary load reduction within one hour.

The Cinergy program illustrates that high market penetration can be achieved among large C/I customers with targeted and customized program offerings. However the restricted annual number of hours (only 96 for the most severe CallOption offering) makes them more suitable for emergency as opposed to economic operations.

(3) *Successful transition of legacy interruptible programs to demand response programs: Baltimore Gas & Electric and Commonwealth Edison*

As noted earlier, utilities have offered traditional load management programs – typically interruptible rates for large C/I customers and direct load control (e.g., air conditioning, water heating, irrigation pumps) for many years. Existing dispatchable load management programs represent a significant national reliability resource – around 30, 000 MW of peak load reduction capability. However, with restructuring, for various reasons, there has been a significant erosion in the stock of customers and the level of enthusiasm of many utilities that administer these programs. In some states where retail competition has been introduced, existing load management programs have been put in "mothballs."

There are several examples, however, of utilities that are devoting significant resources to affecting a successful transition and integration of their legacy load management programs and price-responsive load programs.

Baltimore Gas & Electric (BGE)

Program Description: Baltimore Gas & Electric (BGE) has a portfolio of programs that include direct load control, non-firm, interruptible rates plus newer Quote-style programs.

BGE has several tariffed demand response programs, including Rider 5 (Residential Air Conditioner Control), Rider 6 (Residential Controlled Water Heater Service), Rider 14 (Generation), Rider 16 (Curtailable Service), and Rider 24 Load Response Program (Option 1 for non-firm load response and Option 2 for firm load response).

Target Market: Riders 5, 6, 14 and 16 have been available for many years. Riders 14 and 16 are traditional non-firm rates programs with reservation payments. Riders 14, 16 and 24 target industrial or large commercial premises in the medium (100-500 kW) and large (500-1,000 kW) size ranges. Table A-1 shows customer participation and demand response potential for these three tariffed programs.

Table 4. Customer Participation and Demand Response Potential in selected BG&E Demand Response Programs

Program	Number of Customers	Demand Reduction Potential (MW)
Rider 14	39	28 MW
Rider 16	114	70 MW
Rider 24	11 (large Gen'l Business and Industrial)	14 MW
Rider 24 – Energy Information Pilot	20 large Ind & 50 Gen'l Business	10 MW

Program Design and Operations Features: Riders 14 and 16 customers have interval load meters and are required to reduce their demands to a Firm Service Level (FSL) or by a guaranteed amount (Guaranteed Load Drop). Participants are called using a phone tree and notifications are typically accomplished within 10 minutes. Back-up generators accounted for more than 2/3 of the total 100 MW load drop from these two programs.

Rider 24 Load Response is a demand-bidding program with both a "Quote"-type option (non-firm load response) and a "Call"-type option (firm load response). It operates year-round on an every-day basis. This program is new and improved in 2001 and marketing is still underway. The Option 1 "Quote" program is very simple – day-ahead wholesale power price forecasts are posted on the PJM web page on a daily basis. If the day-ahead prices are attractive enough to a participant, they simply e-mail BGE expressing interest and specifying the hours and the amount of load they will reduce. **Thus, there is no need to notify customers.** The minimum load curtailment for this program is 25 kW, which must be offered between 10 am and 8 pm, and the Locational Marginal Price (LMP) must be greater than the retail rate on which they take service. Any savings (net of retail rates) are split equally between BGE and the customer. All participants have interval meters and load reductions are measured against a rolling baseline load derived from the past five business days, excluding any days where the customer curtailed demand. Customers can receive their load data on a day-after basis on request.

Rider 24 Option 1 (Firm load response) is more complicated. The customer must be able to reduce their demand to a pre-set Firm Service Level (FSL) and must do so on 15 minutes notice upon notification by the ISO or face a penalty. Customers receive a discount on their demand charge in addition to energy payments during curtailment events. No customers signed up for this option in 2001.

Summer 2001 Results: The non-firm programs, Riders 14 and 16, were operated on three occasions in 2001 by BGE as part of PJM's emergency ALM dispatch, yielding over 100 MW each time. Two customers bid in quite frequently in Rider 24 Load Response and another 6 customers bid-in during the very hot days of August when PJM prices for buses in the BGE service territory were as high as $900/MWh. BGE estimates it received an average of 1.5 MW on hot days.

Commonwealth Edison (ComEd)

Program Description: Commonwealth Edison operates numerous demand response programs, including the Rider 32 Energy Coop, Rider 26 Interruptible Service, Rider 30 The Alliance, and the Voluntary Load Reduction program. The Voluntary Load Program is, in principle, both a Contingency and a Market program. It has two options: the standard option and the Maximum Value option. The standard option provides a relatively high incentive and is operated primarily for system emergencies. The Maximum Value option has a much lower minimum incentive payment, and is more likely to be called as a hedge against high wholesale electricity prices.

Target Market: The Voluntary Load Reduction program, or VLR, targets any nonresidential customer who can reduce their demand by 10 kW or 5% of their Summer 2000 demand, whichever is greater.

As of September 2001 there were 3,000 participants on VLR with a total demand reduction potential of 540 MW. The majority of the participants were in the standard option, with about 25% in the Maximum Value option. About 1/3 of the participants are industrial, with the balance being commercial and institutional. The program draws equally from all customer size ranges – small (under 100kW), medium (100-500 kW), large (500-1,000 kW) and very large (over 1 MW).

Program Design and Operations Features: Participants in the VLR program must possess an interval data recorder. Participants are given one hour's notice to curtail and must reduce for 2-7 hours, depending on the curtailment event. For the standard option, curtailments are limited to 15 events and 75 total hours each summer; for Maximum Value, 20 events and 100 hours per year.

Operation of the program is simple. There is no web page. Participants are notified by phone, pager, e-mail or FAX (their choice). Com Ed calculates a customized baseline load with a regression technique that combines previous load data, temperature, day of the week, cloud cover. Com Ed, believes that their measurement & verification approach has proven useful against participants that seek to game the system. Customers generally do not have access to their load data and settlement takes place on an annual basis at the end of the calendar year.

Summer 2001 Results: The VLR program was not operated all during Summer 2001. No system contingencies occurred, and wholesale prices remained below the level at which program administrators believed an attractive performance incentive could economically be offered. A number of other programs – including Riders 30 and 32 – which are fixed-cost, operated on one occasion in 2001, on August 8, when wholesale prices reached $440/MWh, the highest level of the year. Although Commonwealth Edison is still analyzing event results, it appears that customers provided about 480 MW of load reduction out of a potential of 550 MW. This compares to 300 MW in Summer 2000, so the programs are growing rapidly. Customers with back-up generators are key participants in program operation, although their exact contribution to the overall program has not been calculated. It is likely around 1/3-1/2 of the total load reduction.

Program Accomplishments and Outlook. The programs are low-cost and simple to operate and will likely be around as long as there is the possibility of summer supply shortages.

(4) Successful Demand Bidding Program: Portland General Electric

Portland General Electric's Demand Buy Back Program provides a successful and sophisticated example of a voluntary, "quote-type" demand bidding program. In 2001, PGE offered the Demand Buy Back Program with three types of load reduction bidding variants: day-ahead, pre-scheduled (up to one week in advance), and term events (lasting weeks to months). As of September 2001, the program had 26 participants with 175 MW of potential curtailable load. The customer mix is primarily industrial and manufacturing, with some commercial and institutional accounts. Major segments and end-uses represented include pulp & paper, steel, lumber, printing presses, municipal and agricultural pumping, and the City of Portland. Customers as small as 250 kW can now participate, although over two thirds of the participants are large (500-1,000 kW) or very large (over 1 MW). All customers must have interval meters. Participants are paged using an alphanumeric pager that receives information updates from the program web site.

From July 2000 to May 24, 2001, there were 122 daily events, resulting in usage reductions of 90 million kWh and measured load reductions of 162 MW. Term events running from April through September 30, 2001 contributed 187 million kWh and 75 MW. However, the program's last day of full operation was May 24, 2001 when wholesale prices were projected at $300/MWh. PGE would generally base its demand offers on a 50-50 sharing of savings between customers and the utility. The $91.86/MWh "soft" cap on wholesale prices in the West adopted by the FERC reduced the resource potential of this program, as this is below the level at which most participants will bid in.