New Paradigm, Same Players: the Relationship between Reliability and Price-Responsive Demand Response Program Participants in California

Mike Ting, Amy Buege, and Mike Rufo
Itron, Inc. Consulting and Analysis Services Group, Oakland, CA

Abstract

This paper presents the results of an in-depth analysis of the Demand Bidding Program (DBP) participant population in California with a focus on interruptible service customers enrolled in DBP and how their participation influences the outlook for growth in price-responsive demand response (DR) from DBP going forward. Based on results from participation tracking, bidding, load reduction impact, and process analyses, we found that while interruptible customers account for a rather small share of customers enrolled in DBP, they account for significant share of enrolled non-coincident peak load and an even larger share of the load reductions bid by DBP participants during DBP events. In the end, interruptible customers accounted for the majority of total load reductions realized through California's statewide DBP programs in 2005. These findings indicate two important but conflicting participation trends. First, a significant portion of reliability customers have adapted their curtailment planning and actions from the infrequent, compliance-driven framework of reliability programs to the more frequent, voluntary framework of price-responsive programs. However, the fact that a significant portion of participation in price-responsive programs is coming from existing reliability customers also indicates that the level and growth of participation in price-responsive programs from customers who had not previously participated in any DR program is significantly less that it would otherwise appear.

Introduction

This paper presents selected results from a 2005 evaluation of California's statewide demand response (DR) programs for large nonresidential customers, conducted under the guidance of the state's investor-owned utilities, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC). This evaluation built upon the process, market, and impact analyses from the 2004 evaluation of critical peak pricing tariffs and demand-bidding programs, but with an expanded scope that included reliability programs, notably traditional interruptible service tariffs. The overall goal of the evaluation was to assess the extent to which current programs will be able to achieve California's short-term goals for price-responsive DR.

The in-scope programs analyzed in the 2005 evaluation included: the Critical Peak Pricing (CPP) tariff, the Demand Bidding Program (DBP), the Demand Reserves Partnership (DRP) program – collectively referred to as "day-ahead" or "price-responsive" programs – as well as the Base Interruptible Program (BIP), traditional interruptible tariffs, and the Optional Binding Mandatory Curtailment (OBMC) program – collectively referred to as "reliability" programs. Whereas traditional interruptible service tariffs have been offered for over 20 years, California's investor-owned utilities – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) – first offered the BIP and OBMC programs in 2001 and the price-responsive DR programs starting in 2004.

Research Issues

Since price-responsive DR programs were first introduced, demand-bidding programs (DBP) have demonstrated the highest levels of customer enrollment compared to other types of price-responsive DR programs by far. At first blush, DBP programs would thus appear to hold significant promise for the development of price-responsive DR over the short-term in California. However, DBP programs have yet to produce significantly higher load reductions in aggregate than other price-responsive programs with much lower levels of enrollment. This paper presents the results of an in-depth analysis of the DBP participant population with a focus on interruptible service customers enrolled in DBP and how their participation influences the outlook for growth in load reductions from DBP going forward.

Methodology

The analysis presented in this paper leverage a number of sub-studies conducted for the overall 2005 evaluation. These sub-studies included a participation tracking analysis, a bidding analysis, a load reduction impact analysis, and a process analysis. Below, we provide brief overviews of the methodologies and data sources used in each of these sub-studies. For detailed descriptions of these methodologies, we refer readers to the full 2005 evaluation report (Quantum Consulting, 2006).

In the participation tracking analysis, we quantified and tracked customer participation over time in each of the in-scope statewide DR programs based on data from the Customer Information Systems (CIS) of each utility. The CIS data also allowed us to segment participants by size and business type. Size categories were defined based on an account's annual maximum demand as follows:

- Extra Small customers were defined as those having a maximum demand between 20 kW and 100 kW;
- Very Small customers were defined as those having a maximum demand between 100 kW and 200 kW;
- Small customers were those with maximum demand between 200 kW and 500 kW;
- Medium customers were those with maximum demand between 500 kW and 1000 kW;
- Large customers were those with maximum demand between 1000 kW and 2000 kW;
- Extra Large customers were those with maximum demand greater than 2000 kW.

The business type flags were defined based on Standard Industrial Classification (SIC) codes for SCE and SDG&E and a mapping of North American Industrial Classification System (NAICS) codes to SIC codes for PG&E.[1] For our analyses, we defined the following nine business type categories:

- Office;
- Retail/Grocery;
- Institutional;
- Other Commercial;
- Transportation/Communications/Utility (TCU);
- Petroleum/Plastic/Rubber/Chemicals (PPRC);
- Mining/Metals/Stone/Glass/Concrete (MMSGC);
- Electronic/Machinery/Fabricated Metals (EMFM);
- Other Industrial/Agriculture (OIA).

[1] For the full SIC/NAICS mapping, see the full 2005 evaluation report (Quantum Consulting, 2006).

We also defined an alternate set of business type flags in order to facilitate more aggregate comparisons across economic sectors. For such higher-level comparisons, the nine business types defined above were aggregated into three business types as follows:

- Office, Retail/Grocery, and Other Commercial ⇒ Commercial
- Institutional and TCU ⇒ Institutional
- PPRC, MMSGC, EMFM, and OIA ⇒ Industrial

For the analysis of bidding trends by DBP participants, we used utility-provided program event data. These data included information such as confirmation of the notification process, the time period for which the event was called, the event trigger (temperature, price, system emergency, etc), the utility-estimated load reductions per customer resulting from the event, and the payments made to the customers for their in-event curtailments. These data allowed us to analyze the size, number, and timing of load reduction bids placed by each DBP participant during the summer of 2005.

A central component of our 2005 evaluation was the estimation of load reduction impacts achieved by DR program participants. For this analysis, we used customer-specific hourly interval data for all program participants provided by each utility. Impacts were calculated using several different representative-day baseline methods as well as regression-based baseline methods. Currently, settlement for the CPP and DBP programs at each of the three utilities is based on the 3-Day representative day method. However, the impact estimates presented in this paper are based on the 10-Day Adjusted representative day method developed by Quantum Consulting, which was shown to be the most accurate and least biased of the representative-day methods analyzed. For a detailed discussion and comparison of impact estimates from all the different baseline methodologies considered, readers are referred to Buege, et al. (2006). The use of the 10-Day Adjusted method to estimate load impacts rather than a different representative day method does not affect the analytic findings or conclusions presented in this paper.

Finally, we also conducted process evaluations of each in-scope program to analyze customer perceptions of program features and processes, specific curtailment actions taken by customers and their effect on operations, barriers to curtailment, program satisfaction, and likelihood of continued DR program participation. These analyses were based primarily on a series of telephone surveys conducted with participants, including a post-event survey conducted in late August 2005 and an end-of-summer survey conducted in late November 2005. In total, 134 DBP participants completed the post-event survey and 158 DBP participants completed the end-of-summer survey, representing roughly 20 percent and 25 percent of DBP participant population, respectively.

Results

In total, statewide enrollment in price-responsive programs stood at 1,838 accounts and 2,822 MW of non-coincident peak load by the end of the summer 2005 season. Total statewide enrollment in reliability programs stood at 767 accounts and 2,325 MW of non-coincident peak load.

Enrollment in DR programs varied widely across utilities and programs, as Table 1 shows below. Among price-responsive programs, statewide participation on an account basis was highest in the DBP program (1,231 accounts), followed by CPP (410 accounts). Among reliability programs, statewide participation in traditional interruptible tariffs remained significant in 2005 (627 accounts) despite being virtually closed to new enrollment since the 1990s.

Table 2 shows participation in 2005 statewide DR programs in terms of enrolled non-coincident peak load. Among price-responsive programs, statewide participation is again highest in the DBP program, with 1,609 MW of non-coincident peak load enrolled during the summer of 2005. Among reliability programs, statewide participation is again highest in traditional interruptible tariffs, with 1,790 MW of non-coincident peak load enrolled.

Table 1. Statewide 2005 DR Program Participation, Account Basis

3 IOUs	Day-Ahead Programs				Reliability Programs				
	CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	BIP (accts)	OBMC (accts)	INTER (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)	3	46	0	48	0	0	8	8	56
Very Small (100-200 kW)	12	28	4	43	1	0	16	17	59
Small (200-500 kW)	149	431	202	762	6	0	33	39	794
Medium (500-1000 kW)	145	345	26	485	44	0	168	212	635
Large (1000-2000 kW)	74	215	16	282	23	1	192	216	440
Extra Large (2000+ kW)	27	166	37	218	28	43	204	269	403
Unknown	0	0	0	0	0	0	6	6	6
Business Type									
Commercial and TCU									
Office	48	227	7	263	1	0	11	12	270
Retail/Grocery	30	167	157	353	4	0	19	23	374
Institutional	80	108	11	193	4	1	26	31	216
Other Commercial	79	201	68	321	17	4	26	47	350
Transportation/Communication/Utility	47	162	26	231	12	1	69	82	280
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	11	46	4	59	15	3	105	122	152
Mining, Metals, Stone, Glass, Concrete	12	62	5	77	17	10	136	160	191
Electronic, Machinery, Fabricated Metals	55	117	1	156	8	9	77	93	225
Other Industrial and Agriculture	46	138	6	181	23	16	158	196	331
Unclassified									
Unknown	2	3	0	4	1	0	0	1	4
Total Accounts	410	1,231	285	1,838	102	44	627	767	2,393
Unique Customers	197	598	45	780	86	41	474	583	1,192
Utility Breakdown									
PG&E	292	466	169	856	24	31	95	147	956
SCE	8	703	93	803	78	13	501	589	1,229
SDG&E	110	62	23	179	0	0	31	31	208

Table 2. Statewide DR Program Participation in 2005, Non-coincident Peak Load Basis

3 IOUs	Day-Ahead Programs				Reliability Programs				
	CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	BIP (MW)	OBMC (MW)	INTER (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)	0	0	0	0	0	0	0	0	1
Very Small (100-200 kW)	1	2	0	3	0	0	2	3	6
Small (200-500 kW)	52	139	73	257	2	0	12	14	268
Medium (500-1000 kW)	101	244	16	339	31	0	126	157	450
Large (1000-2000 kW)	104	296	25	391	33	2	273	308	618
Extra Large (2000+ kW)	121	927	825	1,831	185	418	1,376	1,843	3,089
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	51	152	15	190	1	0	21	22	217
Retail/Grocery	15	61	62	137	6	0	11	17	153
Institutional	45	166	56	260	7	5	67	78	303
Other Commercial	64	243	39	318	15	25	59	98	377
Transportation/Communication/Utility	37	220	613	865	16	3	182	201	972
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	16	71	17	102	28	31	241	286	323
Mining, Metals, Stone, Glass, Concrete	20	216	118	346	107	185	631	807	853
Electronic, Machinery, Fabricated Metals	62	231	4	277	18	84	257	354	540
Other Industrial and Agriculture	70	240	15	319	48	87	323	455	685
Unclassified									
Unknown	1	8	0	8	7	0	0	7	8
Total Non-coincident Load	380	1,609	939	2,822	250	420	1,790	2,325	4,433
Utility Breakdown									
PG&E	290	692	745	1,640	53	225	416	661	2,094
SCE	6	853	171	1,029	197	195	1,355	1,646	2,171
SDG&E	84	64	24	153	0	0	19	19	167

An important aspect of program participation that is not evident from Tables 1 and 2 is that customers can participate in multiple programs simultaneously. Figure 1 below shows a matrix of in-scope 2005 DR programs and indicates (in bold) the number of customers participating in multiple demand response or reliability programs. Restrictions to multiple program participation are shown as a dash. As the figure shows, the number of customers participating in multiple programs has been limited. However, Figure 1 shows one important overlap in the participant population – roughly 30 percent of customers currently enrolled in reliability programs (i.e. interruptible tariffs, BIP, and/or OBMC) also participate in DBP. This overlap is important to note not only because customers in reliability programs tend to be larger customers but also because customers in reliability programs tend to have larger and more developed load reduction capabilities compared to other customers, particularly customers enrolled in traditional interruptible tariffs.

	CPP	DBP	DRP	BIP	OBMC	Interruptible
CPP	410					
DBP	**82**	1231				
DRP	**6**	-	269			
BIP	-	**30**	**2**	102		
OBMC	-	**10**	**3**	**2**	44	
Interruptible	-	**172**	**4**	-	**4**	627

Figure 1. Customer Participation in Multiple Day-Ahead and Reliability Programs

The remainder of this paper presents the results of an in-depth analysis of the overlap between the DBP participant population and interruptible service and how this overlap influences DBP program performance and the outlook for growth in load reductions from DBP going forward.

Figure 2 and 3 show the breakdown of participants in DBP and traditional interruptible tariffs by business type and customer size, respectively. As the figures show, the interruptible customers that also participate in DBP are fairly representative of the total population of interruptible customers, both in terms of business type and customer size. Compared to the rest of the DBP participant population, however, interruptible customers that also participate in DBP are clearly much larger on average and tend to be Industrial customers rather than Commercial or Institutional customers.

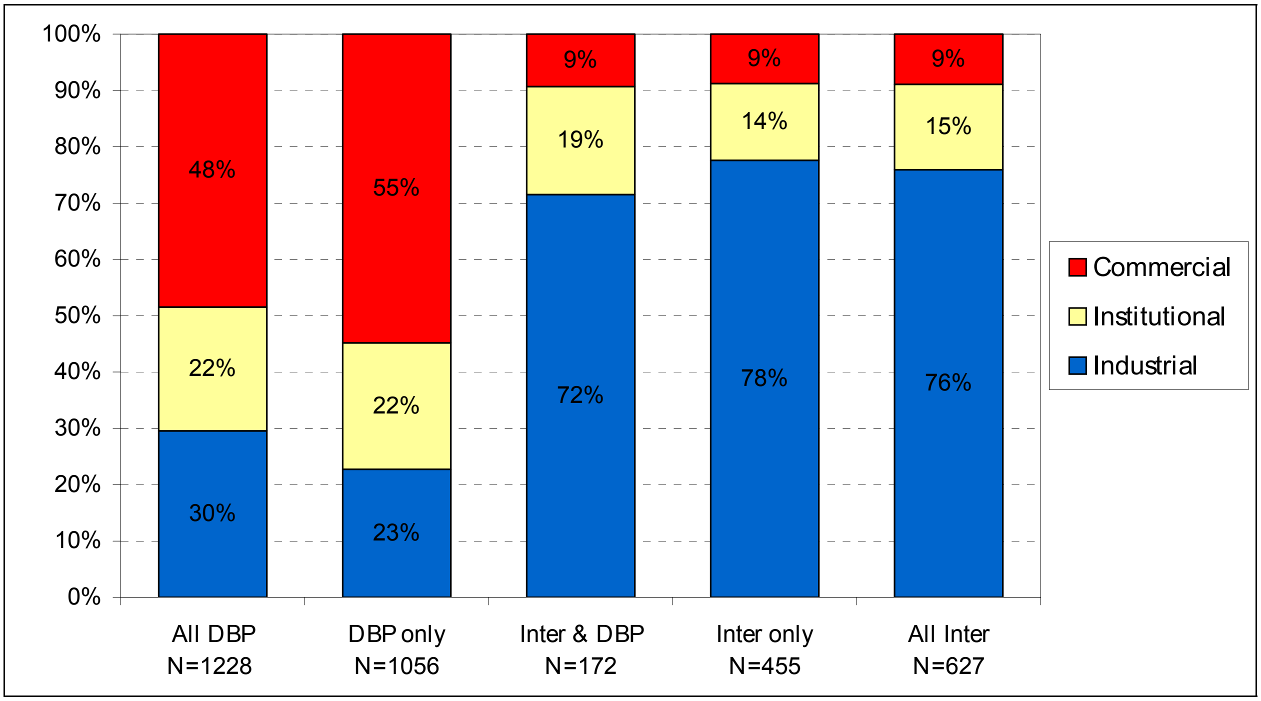

Figure 2. Participation in DBP and Traditional Interruptible Tariffs by Business Type

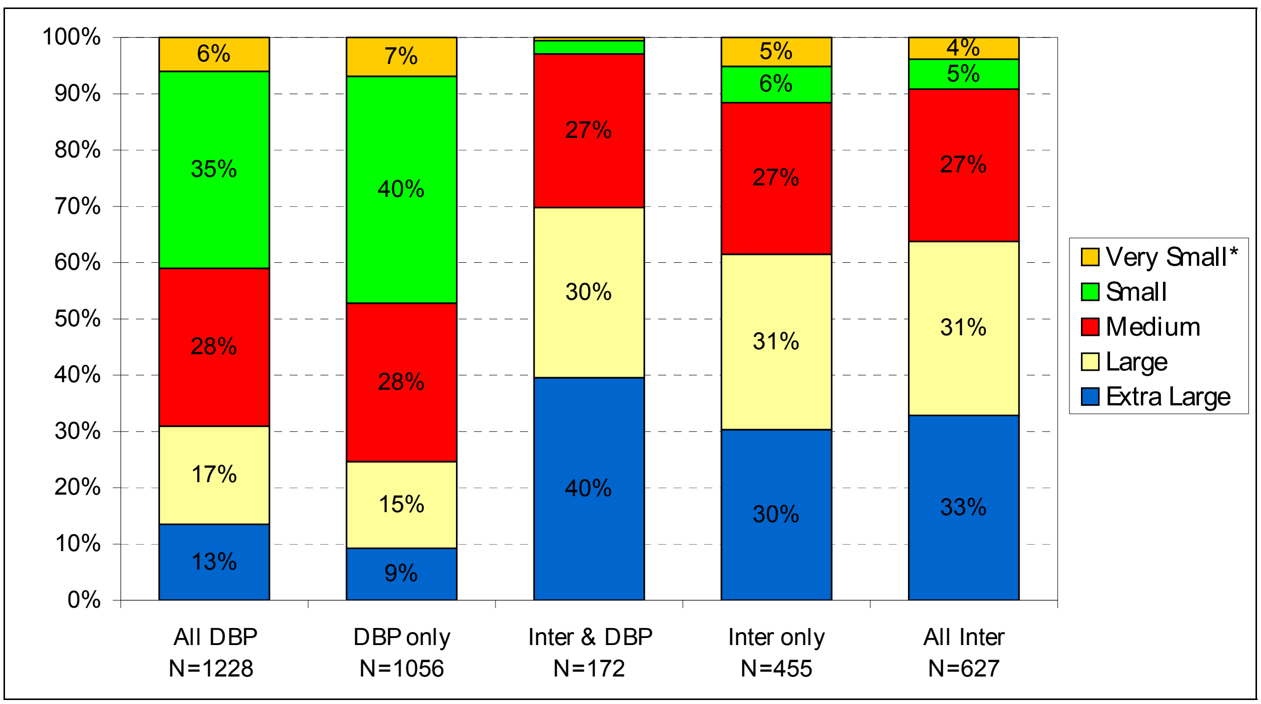

Figure 3. Participation in DBP and Traditional Interruptible Tariffs by Customer Size

To analyze how these interruptible customers affected the performance of the DBP program overall, we first analyzed DBP bidding and load reduction trends across all participants and then compared trends between interruptible and non-interruptible customers.

As Tables 1 and 2 showed previously, enrollment in DBP is relatively high statewide. However, DBP program event data show that the number of DBP participants actually placing bids during summer 2005 events was very low. Table 3 provides a summary of some the key DBP bidding statistics for 2005.

The table shows that, in total, 22 percent of PG&E, 37 percent of SDG&E and 14 percent of SCE DBP participants placed a bid for one or more of the 2005 events. The average bid amount for PG&E participants was more than twice that of SCE participants and approximately three times the size of the SDG&E participants' bids. The overall bid rate across all 2005 DBP events was just 7 percent for PG&E, 5 percent for SCE and 14 percent for SDG&E.

Table 3. Summary of DBP Bid Statistics by Utilities

DBP Bid Analysis	Utility		
	PG&E	SCE	SDG&E
# DBP Events in 2005	17	13	12
Percent of DBP Participants who placed a bid in 2005	22%	14%	37%
Average Number of Bids Placed per Bidder	5.4	4.6	4.7
Average Bid Amount*	1,029	416	343
% of DBP Bidders who Bid for only 1 Event	20%	27%	32%
% of Events for which DBP Bidders placed Bids	32%	35%	39%
Overall Summer 2005 Bid Rate (Bids/Bid Opportunities)	7%	5%	14%

* For PG&E Average Bid Amount was over last 10 events where true bids were captured.

Table 4 presents the estimated average hourly load reduction impacts from the DBP program, in terms of MW and percent reductions, by utility over all 2005 DBP event hours (273 hours in total across all three utilities). Due to the high level of variation in load reduction impacts across both utilities and summer 2005 events, Table 4 provides both the mean impact and the impacts falling in the 25th and 75th percentile ranges. The mean and percentile ranges correspond to the average impact over all event hours for DBP bidders. As Table 4 shows, DBP bidders delivered load reductions totaling between 5 and 15 MW over half of the DBP summer event hours. Averaged over all DBP event hours, DBP bidders delivered approximately 11 MW of load reductions. These MW impacts correspond to average load reductions among DBP bidders of 26 percent for PG&E, 5 percent for SCE, and 10 percent for SDG&E.

Table 4. Average MW Impact Estimates Across All 2005 DBP Event Hours

Program Impact Ranges for DBP (MW)				
Utility	Event Hours	Mean	75^{th} Pct	25^{th} Pct
PG&E	136	8.4	10.3	5
SCE	96	2.3	4.3	-0.1
SDG&E	41	0.5	0.7	0.2
Statewide*	273	11.2	15.3	5.1

When considering interruptible customers that also participate in DBP, a comparative analysis of bidding trends and load reduction impacts shows that interruptible customers accounted for the majority of both total load reductions bid and total load reductions delivered by DBP program participants in California in 2005. Table 5 below shows that while less than 20 percent of SCE's DBP participants take service on interruptible tariffs, these customers delivered more than half of the DBP program impacts over the course of the 2005 summer events. In PG&E's territory, only 7 percent of DBP participants take service on interruptible tariffs, but these customers delivered nearly 60 percent of the DBP program impacts in 2005. In SDG&E territory, the overlap is much smaller with only 3 percent of the DBP participants taking service on interruptible tariffs, accounting for 7 percent of the 2005 DBP program impacts overall. Across the three utilities, the bids placed by interruptible customers were between 3.5 and 8.5 times larger than the bids coming from the non-interruptible service customers.

Table 5. Overlap Analysis of Customers who are Enrolled in Both DBP and the Traditional Interruptible Service Tariffs at their Respective Utility

DBP and Traditional Interruptible Participant Overlap Analysis	Utility			Statewide Average
	PG&E	SDG&E	SCE	
% of DBP Participants who are also Trad Inter Parts	7%	3%	19%	14%
% of DBP Bidders who are also Trad Inter Parts	26%	7%	19%	21%
Average Bid Amt for Trad Inter Parts	2119	1651	1241	1419
Average Bid Amt for **Non** Trad Inter Parts	587	238	147	318
% of **Estimated Load** from DBP Bidders who are also Trad Inter Parts	39%	11%	32%	34%
% of **Bids** from DBP Bidders who are also Trad Inter Parts	56%	36%	67%	59%
% of **Impacts** from DBP Bidders who are also Trad Inter Parts	58%	7%	54%	56%

In the context of these findings, we also sought to explore how self-reported curtailment actions differ between interruptible customers and non-interruptible customers enrolled in DBP, and how those differences relate to the size of actual load reductions achieved by DBP participants. Using data derived from the post-event and end-of-summer surveys, we summed the customer-level hourly load reductions across customers who reported similar sets of curtailment actions.[2] The results, shown below in Figure 4, provide rough estimates of the relative impact of various curtailment actions on actual load reductions achieved from the DBP program. Due to the small sample size associated with these results, the total load reductions from customers that reported similar curtailment actions are shown not normalized across customers or number of events. Rather, they are shown as overall contributions to the total statewide DBP program impacts for all summer 2005 events. Due to data limitations, we did not attempt to scale the impact contributions to represent all actions from the entire population of DBP participants. Thus, the load reductions represented in Figure 4 account for only 24 percent of total impacts from the DBP program. Nonetheless, the analysis summarized in Figure 4 serves as a useful first order decomposition of total program impacts into specific groups of curtailment actions.

[2] Due to the frequency of customers who cited using multiple curtailment actions, responses were grouped preferentially into the following 'sets' of curtailment actions: backup generation plus other actions, complete operations shutdown plus other actions, partial shutdown of operations plus other actions, reduce production processes plus other actions, reschedule energy management systems plus other actions, and reduce discretionary end uses only. These sets were chosen based on the assumption that certain actions produce large, predictable load reductions (e.g. backup generation and complete shutdown) and tend to swamp other types of load reductions.

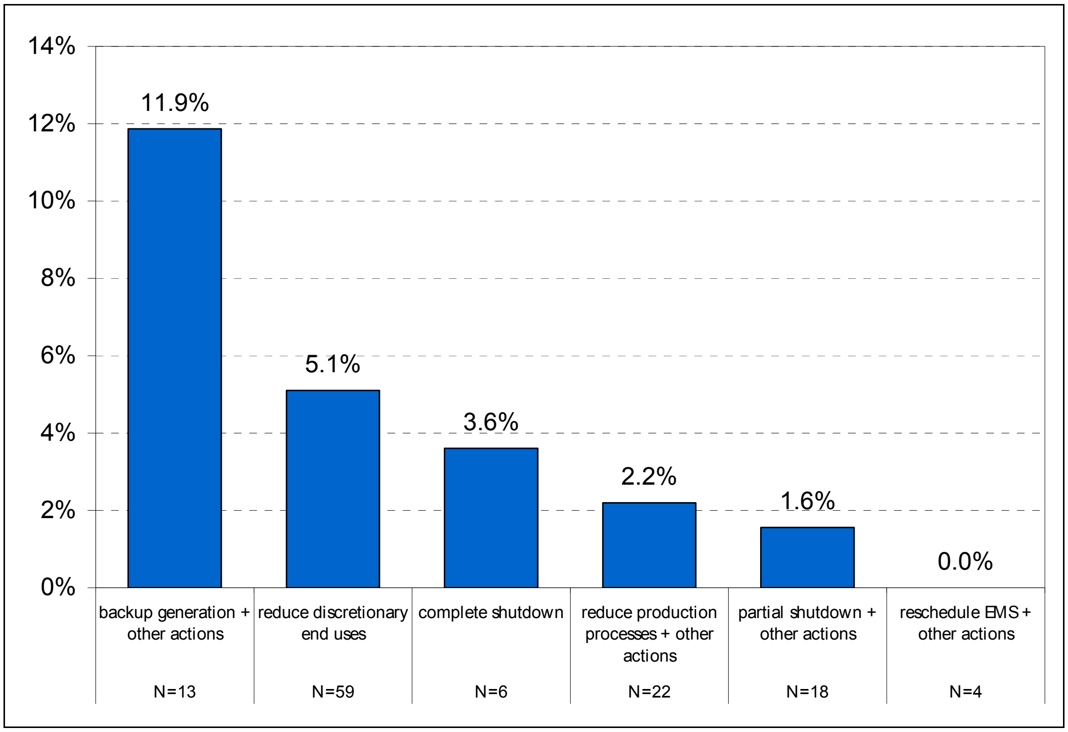

Figure 4. Contributions to Total Statewide DBP Program Impacts by Self-Reported Curtailment Action

The results in Figure 4 above suggest that, within the sample population of DBP participants shown, the set of curtailment actions that made the largest contributions to total DBP program impacts were the use of backup generation grouped with other actions (12% of total DBP impacts), followed by reducing discretionary end uses (5% of total DBP impacts). The results for backup generators are consistent with the fact that over half of total DBP program impacts come from interruptible customers that participate concurrently in DBP and that interruptible customers frequently cited the use of backup generation as a curtailment action during reliability program events.

Conclusions

These findings indicate two important but conflicting participation trends in California's DR programs. First, a significant portion of reliability customers have adapted their curtailment planning and actions from the infrequent, compliance-driven framework of reliability programs to the more frequent, voluntary framework of price-responsive programs. From this perspective, the utilities and the state are now able to get more flexible and more frequent DR from the existing reliability resource base. Second, the fact that a significant portion of participation in price-responsive programs is coming from existing reliability customers indicates, however, that the level and growth of price-responsive program participation from customers who had not previously participated in any DR program is significantly less that it would otherwise appear. Still, the fact that a relatively large share of the customers currently enrolled in DBP have not actively bid or executed load reductions during DBP events suggests that technical and educational assistance programs targeted towards that segment of DBP enrollees hold the potential to increase overall DBP program impacts significantly over the short term.

For policymakers and program planners, these findings indicate that early successes in customer recruitment and participation in voluntary, DBP-style DR programs should be interpreted with caution. Specifically, long-term growth in program participation and, more importantly, load reductions from such programs are unlikely to follow early-year trends. Indeed, our findings suggest that longer-term growth in participation in voluntary DBP-style programs will likely require sustained program marketing, targeted technical assistance and education, and perhaps increasing incentive levels in order to recruit new, active participants significantly beyond the existing reliability customer base.

References

Quantum Consulting, 2006. "Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs." Prepared for Southern California Edison Company and Working Group 2 Measurement and Evaluation Committee. April 28.

Buege, Amy, Rufo, Michael, Ozog, Michael, Violette, Dan, and McNicholl, Susan, 2006. "Prepare for Impact: Measuring Large C&I Customer Response to DR Programs." Proceedings of the 2006 ACEEE Summer Study on Energy Efficiency in Buildings.