Section 4
Market Potential

SECTION 4: MARKET POTENTIAL

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1. INTRODUCTION AND SUMMARY OF DR POTENTIAL BENCHMARKS

1.1 Introduction

The potential for demand response (DR) in a given market area is one of the key program planning inputs that determine the significance of DR as a tool to meet electric system expansion needs and maintain electric price stability. DR potential studies are most often done for one or more of three purposes:

1. To develop part of the demand-side section of an integrated resource plan as the traditional planning tool in regulated markets or as part of a capacity adequacy forecast as common in the deregulated markets.
2. For DR program planning or screening.
3. As part of the certificate of need for a new generating plant. In this instance, the intent of the study is to show that demand-side programs cannot eliminate the need for the new plant.

However, rigorous DR potential studies are generally of recent vintage, and the tools and techniques used in such studies are much less fully developed than those for energy efficiency potential studies. Utilities around the world have conducted literally hundreds of robust energy efficiency (EE) potential studies in the past 30 years, and numerous computer models have been developed to forecast long-term EE potentials.

Many of the concepts and approaches used for EE potential studies have been carried over to DR potential studies. One of the most fundamental is that EE and DR potential studies are based on analyses of customer-level data of various types, not utility system load data such as load duration curves. This is because the intent of most DR potential studies is to estimate the magnitude of DR resources that can feasibly be achieved over a given period of time. Three types of program potential are commonly assessed as part of energy efficiency potential studies, and these concepts have been carried over to DR potential studies. The three types of program potential are:

- **Technical potential**: the amount of savings that would be realized if all eligible customers adopted DR measure(s) without regard to economic or market barriers. A simple example of DR technical potential is the amount of demand reduction that would occur if all residential customers with central air conditioners (CACs) signed up for a direct load control program that only covered residential CACs.

- **Economic potential**: the amount of technical potential that would be realized from DR measures that meet a specified economic criteria. Such economic criteria have included the "total resource cost test", a positive net present value, or a customer payback period of a given number of years or less.
- **Market or achievable potential**: the amount of savings that could realistically be achieved by an actual DR program over a certain period of time.

Technical and economic potential are really "thought experiments" that cannot be achieved through normal market mechanisms. Economic barriers will prevent all technical potential from being realized, and market barriers will prevent all economic potential from being realized. Technical or economic potential estimates are sometimes used as benchmarks to compare with market or achievable potential estimates. The higher the ratio of market potential to economic potential, for example, the more effective a DR program is estimated to be in terms of realizing program potential that is cost-effective.

Market potential is usually the most difficult to estimate of the three types of program potential. Market potential estimates require estimates of customer participation in DR programs, which experience has shown to be the most difficult of the DR potential inputs to accurately forecast. It is usually hard to know the shape of the customer adoption curves for a given technology or program, and it is also difficult to estimate where on the curve a given program is at a certain point in time.

Based on the information that the project team has collected to date, utilities have primarily estimated DR potentials using one or more of the following approaches:

1. Making projections based on their recent DR program results.
2. Using the results from other utilities' long-running and successful DR programs.
3. Customer survey approaches.
4. Computer modeling approaches.

This report will focus on the latter three approaches for estimating DR potential. The first section on DR potential benchmarks presents results from top-performing DR programs in the US and Canada.

The second section of this report focuses on survey approaches to estimating DR potential. The discussion in this section focuses on the most useful situations for using survey approaches to estimate DR potential, and presents a sample survey instrument for estimating the DR potential for a residential direct load control program. Three additional survey instruments are presented in Exhibits B, D and H at the end of this chapter. One of these survey instruments was used in a recent California DR program evaluation that used a survey approach to estimate DR potential.The executive summary of the evaluation report is also presented in Exhibit C.

The third section discusses computer modeling approaches to estimating DR potential. In this section, several modeling approaches that consulting firms have developed are summarized and reviewed from the standpoint of assessing which modeling approaches work best for various objectives. Several publicly available reports from projects in which these models have been used to estimate DR potentials are also presented in Exhibits E, F, and G.

1.2 Summary of DR Potential Benchmarks Developed

DR potential benchmarks are developed for three types of demand response programs. These benchmarks are based on best in class DR programs as identified through a survey of 40 North American utilities discussed below.

DR Program Type	Customer Class	DR Potential Benchmark
Direct Load Control	Residential	10% of residential peak demand
Interruptible Rates	Commercial/Industrial	10% of C/I peak demand
Demand Bidding/Buyback	Commercial/Industrial	8%-9% of C/I peak demand

The data collected through the North American utility DR survey was insufficient to allow development of additional DR potential benchmarks for other types of DR programs.

2. DR POTENTIAL BENCHMARKS

2.1 Introduction and Methodology

This section of the report presents results from best-in-class DR programs conducted by US and Canadian utilities. This information can be a useful set of tools to quickly estimate demand response potential for utilities that are relatively new to demand response, or have been conducting programs for several years, and are unsure how much untapped potential remains in their market area.

The DR potential benchmarks presented in this section are adapted from the results of a survey that Summit Blue Consulting conducted of utility demand response programs in the United States and Canada. The focus of this survey is the demand response programs that individual North American utilities are conducting. This focus on individual utility programs allowed the simplest identification of top-performing programs. Summit Blue staff interviewed demand response program managers or other staff involved with their utilities' demand response programs at 40 utilities across North America.

The utilities surveyed range from companies with peak demands of 700 MW to 35,000 MW. About 90% of the utilities surveyed are American, while 10% are Canadian. Approximately 90% of the utilities surveyed are investor-owned utilities, while 10% are municipal or cooperative utilities. Approximately two-thirds of the utilities surveyed operate primarily in traditionally regulated states, while the other third of the utilities surveyed operate primarily in currently restructured states. These latter states include Georgia, Illinois, Massachusetts, Michigan, Montana, New Jersey, New York, Pennsylvania, Ohio, Texas, and Washington, D.C.

The data that the project team collected on both residential and commercial/industrial utility demand response programs through this survey includes:

- The specific demand response programs that utilities are currently conducting, how long the programs have been operating at each utility, program eligibility requirements, and how utilities market the programs to their customers.
- Program pricing structures or rate discounts.

- Relevant general utility information, such as their standard rates, their number of residential and commercial/industrial customers, and peak demands.
- Any load control equipment that utilities provide to customers as part of their programs, how customers' loads are monitored through the programs, and how their load monitoring or billing information is processed.
- Program performance information, including the number of customers participating in each program, the peak demand reductions that utilities realize from each program, and how utilities calculate the latter. Also, whether the programs are expanding, in maintenance mode, or declining, and the reasons for their status.
- Planning and analysis that utilities conduct regarding these programs. This information includes the extent to which they conduct market potential studies for the programs and how they do so, the type of benefit-cost analysis they conduct for the programs, and how they incorporate the programs into their long-term system planning.
- The utilities' satisfaction with various aspects of their programs, and which program elements they would like to change.

Summit Blue used professional consulting staff and one intern with demand response experience to conduct the telephone surveys. A 47-question survey instrument was used to collect data for the project, and is presented in Exhibit A. Most often residential DR program managers and commercial/industrial DR program managers were interviewed separately. In some cases utility rate department staff was interviewed instead.

The data presented in this report is generally self-reported by the utility staff surveyed. In several instances utilities provided regulatory reports that they had filed that documented the status of their programs at the time, but such reports were usually unavailable. The data provided by the utilities surveyed was checked for reasonableness, but could not be independently verified, given the limited scope of this project.

2.2 Residential DR Program Benchmarks

Residential DR program potential benchmarks are presented separately for direct load control programs and time-differentiated pricing programs. In the survey conducted for this part of the project, the project team interviewed utility representatives about four types of demand response programs that at least some utilities offer to residential customers:

1. **Direct load control (DLC):** Through these programs, customers allow their utility to directly control their central air conditioner, water heater, or other types of major electrical equipment. Utilities cycle this equipment on and off using some type of control mechanism during peak demand periods, usually in alternating 15 minute cycles. Utilities usually offer customers some type of rate discount as an incentive in these programs. Many utilities have been offering these programs for 10 or more years.

2. **Time-of-use (TOU) rates:** The most common type of TOU rates are "two-part" rates that charge customers a higher "on-peak" price than the standard flat utility rate during daytime hours, and a lower "off-peak" price during nighttime hours and weekends. Some utilities offer a "three-part" TOU rate, in which both the on-peak and off-peak periods are shorter than the typical two-part TOU rate periods, and also includes a "shoulder" period between the on-peak and off-peak hours, during which time prices are between the on-peak and off-peak

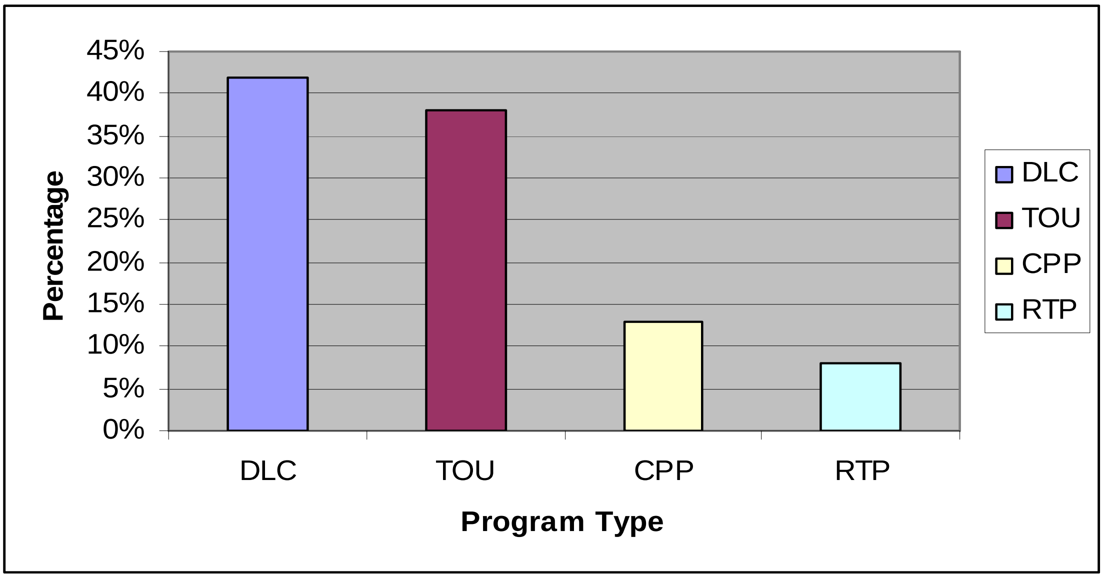
prices. Many utilities have been offering two-part TOD rates for 20 or more years, while all three-part TOD rates are of relatively recent vintage.

3. **Critical peak pricing (CPP) rates:** These are similar to TOU rates, but add a "critical peak" period and rate. The "critical peak" period is usually 1% or fewer hours throughout the year, during which time the utilities' production or power purchase costs are highest. Electric prices during this period are higher than the regular TOU on-peak prices. These programs all started in 2001 or later.

4. **Real-time pricing (RTP):** Prices offered through these programs are tied to some type of hourly pricing benchmark, such as the power pool's RTP rate, or a utility's commercial/industrial hourly pricing rate. These programs are all of recent vintage.

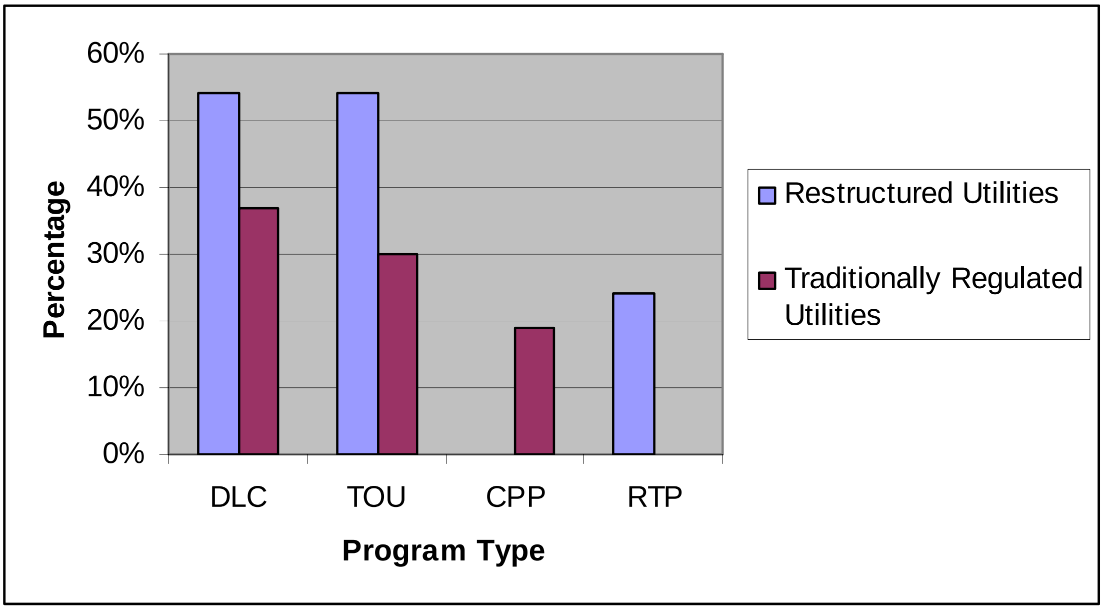
It is interesting to note that almost three-fourths (73%) of the utilities surveyed are conducting at least one type of DR program for residential customers. The most prevalent residential DR programs are DLC programs and two-part TOD rates, each conducted by about 40% of the utilities surveyed. Figure 1 shows the percentage of utilities conducting each type of residential DR program.

Figure 1. Percentages of Utilities Offering Different Types of Residential DR Programs (N=40)



Interestingly, a higher percentage of the utilities surveyed that primarily operate in restructured states were conducting DLC, TOU, and RTP programs than the utilities serving traditionally regulated states. No traditionally regulated utilities are offering residential RTP programs, and no utilities operating in restructured states are offering residential CPP programs. Figure 2 shows the percentages of restructured and traditionally regulated utilities conducting each type of residential DR program.

Figure 2. Percentages of Traditionally Regulated and Restructured Utilities Offering Different Types of Residential DR Programs (N=40)



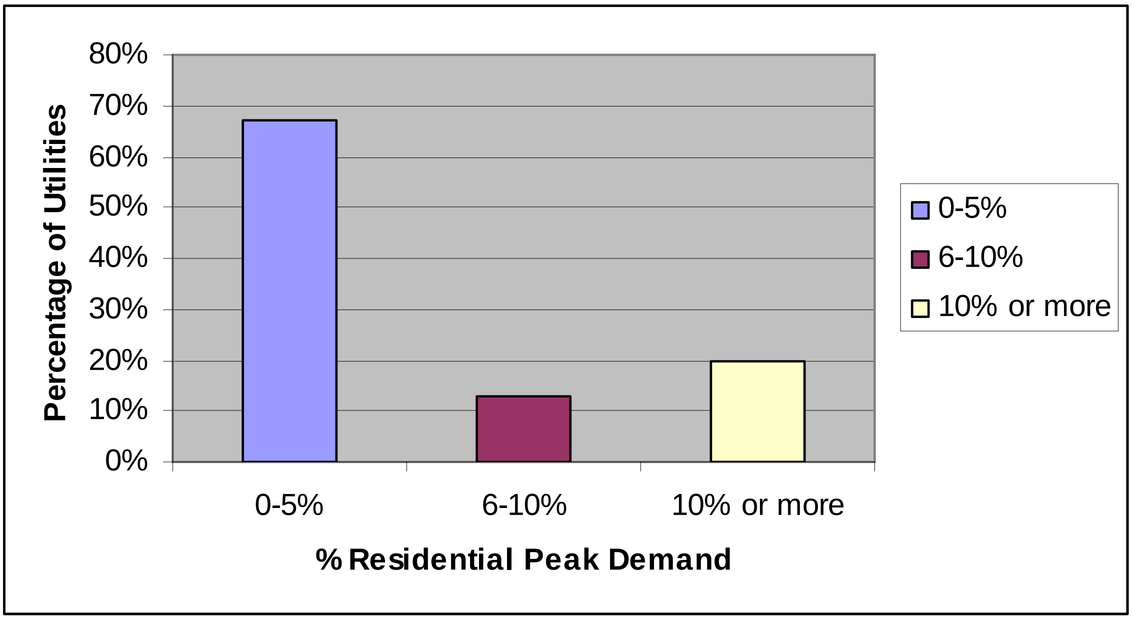
2.2.1 Residential DLC Program Benchmarks

The primary benchmark used for residential DLC programs is the ratio of the programs' total peak demand reduction impact to the utilities' residential peak demand. This benchmark measures the significance of the DLC program to utilities, and provides an indicator that is normalized for the size of the utility. Similar benchmarks are used for other utility DR programs in the following sections of this report.

From the survey results, about 20% of the utilities surveyed that are conducting residential DLC programs reported DLC peak demand impacts that are 10% or more of their residential peak demands. For residential DLC programs, this 10% of residential peak demand reduction is a reasonable DR potential benchmark for this program type. This benchmark is an aggressive and stretching goal for utilities new to this type of program, but it is not necessarily the best result possible for this type of program. As will be discussed further below, one of the utilities whose program impacts were in the top group of utilities surveyed has achieved program impacts that are almost double the 10% benchmark. There are likely other utilities that the project team was not able to survey whose program results also exceed the 10% benchmark.

However, about two-thirds of the utilities surveyed report total peak demand reductions from their DLC programs that are less than 5% of their residential peak demands. These results are portrayed graphically in Figure 3 on the next page. The median percentage of residential DLC peak demand reduction achieved by the utilities surveyed is 3%, while the corresponding mean is 5%.
It is interesting to note that all three of the largest impact DLC programs are conducted by traditionally regulated utilities. One of the intermediate impact (6% of residential peak demand) programs is conducted by a utility (Detroit Edison) operating in a restructured state. However, the mean peak demand impact for traditionally regulated utilities conducting DLC programs is 6% of residential peak demand, compared to a mean 2% of residential peak demand reduction for utilities operating primarily in restructured states.

Figure 3. Residential DLC Program Impacts as Percentages of Residential Peak Demands (N=16)



The three top-performing residential DLC programs are rather different from each other. Xcel Energy's Minnesota Saver's Switch program and Madison Gas and Electric's (MG&E's) Power Control program both focus on cycling central air conditioners. MG&E's program is only operated during actual system emergencies, and has not been activated since 1998. Xcel Energy generally activates its program several times every year during significant peak periods. Xcel Energy's program impacts account for 12% of its residential peak demand, while MG&E's program impacts amount to about 11% of its residential peak demand. Both companies are summer-peaking utilities. Xcel Energy's program has been in operation for 15 years and MG&E's program for 14 years, so both companies' peak program impacts have averaged 0.8% of their residential peak demands per year of operation.

Otter Tail Power Company operates several direct load control programs covering electric water heaters, electric space heating systems, central air conditioners, and other equipment. In total, their program impacts equal about 19% of their residential peak demand. Their program impacts are divided approximately equally between those from space heating control and those from water heating control and other measures. Otter Tail is a winter peaking utility.

Otter Tail has been operating DLC programs longer than any other utility surveyed. Its main water heating DLC program has been in operation for about 60 years, while its main space heating DLC program has been in operation for about 25 years. The central air conditioner component of their program is only three years old, and has attracted limited program participation to date. Overall, their DLC peak demand reductions average about 0.3% of its residential peak demand per year of operation.

It is interesting to note that the utilities conducting the largest impact DLC programs of the utilities surveyed are all located in northern American states. So large summer cooling loads are not required for DLC programs to have significant peak demand impacts. Most of the utilities whose total residential DLC program impacts were much less than 10% of their residential peak demands had either started their DR programs in 2000 or later, or had not aggressively marketed their programs for several years.

Those two factors explain why the program impacts of the utilities operating in restructured states are so much lower than the impacts for the traditionally regulated utilities. The mean

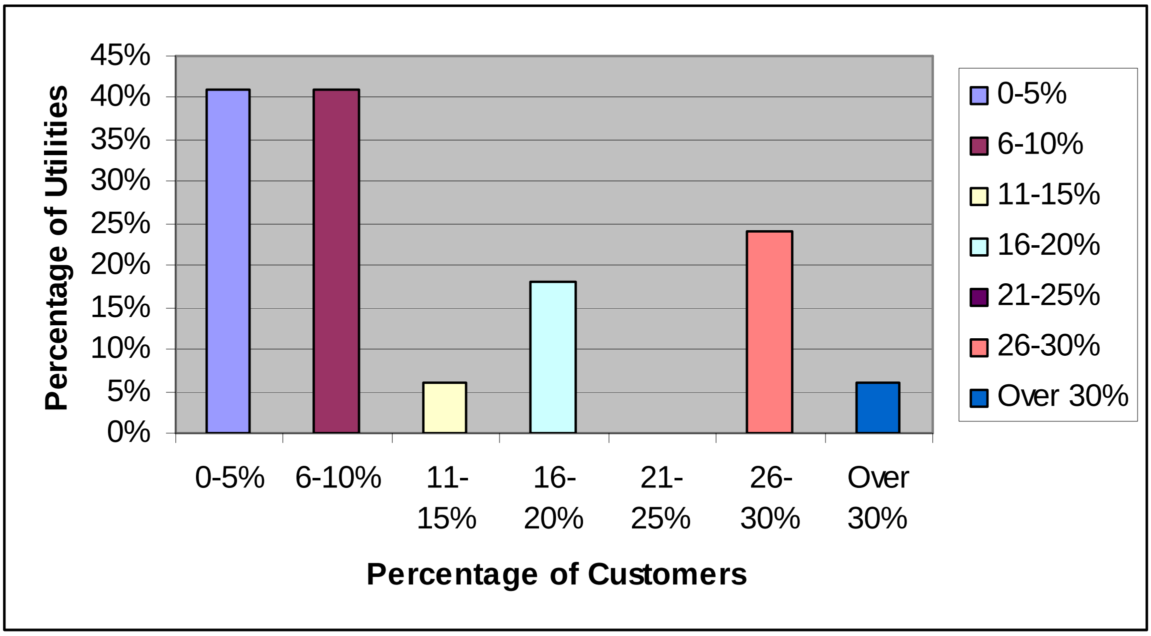
DLC program starting year for the traditionally regulated utilities is 1985, compared to 1993 for utilities operating in restructured states. So the traditionally regulated utilities have been conducting their DLC programs for almost twice as many years on average as the restructured utilities. Also, 70% of the traditionally regulated utilities that are conducting DLC programs report that their programs were still expanding in 2004, and 30% were in maintenance mode. For the utilities in restructured states that are conducting DLC programs, 38% report that their programs were expanding in 2004, 38% report that their program were in maintenance mode, and 25% report that their programs had been suspended or terminated due to restructuring in their states. The mean starting date for the restructured utilities' DLC programs that are still expanding is the year 2000, so these programs had only been in operation for four to five years at the time of these surveys.

About 30% of all the utilities surveyed have enrolled 25% or more of their eligible customers in their DLC programs. Of the three top-performing programs, Xcel Energy has signed up about 28% of all its residential customers for Saver's Switch, but only about half of its residential customers qualify for the program, so about 56% of its eligible customers are participating in the program. (Its single family customers with central air conditioners qualify for the program.) For Otter Tail Power, about 29% of its total residential customers are participating in at least one of its DLC programs. The company estimates that almost all of its customers are eligible for at least one of its DLC programs. MG&E's customer participation rate is about 15% of its total residential customers.

In contrast, about 40% of the utilities surveyed reported DLC program participation rates of 5% or less. The mean percentage of customers that utilities conducting DLC program have enrolled in their programs is 14% of those eligible to participate, and the median enrollment rate is 11% of eligible customers. The mean customer enrollment percentage for traditionally regulated utilities is 17%, about 70% higher than the 10% mean enrollment rate for restructured utilities. DLC program participation rates for the utilities surveyed are portrayed graphically in Figure 4 below.

The median peak demand reduction impact per participating customer for the utilities surveyed is 1.0 kilowatts each, while the mean value is 1.1 kW per customer. For the three top-performing programs, Xcel Energy's peak reduction per customer is the same as the median value of 1.0, while both MG&E and Otter Tail's values are about 1.6 kW per customer. Otter Tail's per unit impacts are higher than average due to the large impacts from its space heating program elements. MG&E's per unit impacts are higher than average due to its ability to completely turn its customers' air conditioners off during an emergency.

Figure 4. Percentages of Eligible Customers Participating in Residential DLC Programs (N=17)



2.2.2 Residential Pricing Program Benchmarks

Participation in TOD, CPP, and RTP rates and other types of residential DR programs is generally low, ranging from almost zero to 4% of eligible customers. For CPP and RTP rates, the low rates of overall customer participation are not surprising, as all of these programs are three years old or less, and most have been in pilot program mode to date.

Only one utility surveyed, Arizona Public Service, has enrolled significant numbers of its customers on a voluntary TOD rate. It has enrolled almost 40% of its customers on TOD rates, primarily through enrolling its new customers. The circumstances of its success with TOD rates are somewhat unusual. APS' standard residential rates have an inclining block structure, meaning that customers' rates increase with use in discrete steps, and its most expensive standard price is 11.99¢/kWh. This is only slightly less than their TOD on-peak price of 12.8¢/kWh. Given their customers' load characteristics, most customers with new homes will reduce their electric bills on TOD rates compared to standard residential rates. Nonetheless, APS estimates that the TOD price structure results in customers reducing their demands by about 0.65 kW each compared to what their demands would be on standard rates. So the company estimates that their TOD rate program impacts amount to about 6% of their residential peak demand.

One could view this 6% of residential peak demand reduction through a TOD rate program as a performance benchmark for this type of program. However, this result was only achieved by one company, about 8% of those offering this type of rate. Given the experiences of the other utilities offering this type of TOD rate, APS' success with this type of program is unlikely to be duplicated by utilities whose standard residential rates are not structured in an inclining block manner.

2.3 Commercial/Industrial DR Program Benchmarks

Commercial/industrial DR program potential benchmarks are presented separately for interruptible rates, demand buyback/bidding programs, and other C/I DR programs. In the survey conducted for this part of the project, the project team interviewed utility representatives about six types of demand response programs that at least some utilities offer to commercial/industrial customers:

1. **Interruptible rates (IRs):** Through these programs, utilities offer customers generally fixed price discounts for reducing their loads to certain levels during peak demand periods. Customers are usually given one to two hours notice before the start of a control period to reduce their loads to the agreed upon levels. Utilities often require multi-year contracts with customers as a condition of program participation, and usually penalize customers if they fail to reduce their loads to the levels specified in their contracts.

2. **Demand "Bidding" or "Buy-back" (DBB):** These programs are similar to interruptible rate programs, but are newer vintage programs that are designed to be more flexible and give customers more options. The rate discounts offered to customers are usually linked to spot market electric prices in some manner. Customer participation and the amount they reduce their loads during peak periods are usually optional.

3. **Direct load control (DLC)**: Through these programs, customers allow their utility to directly control their central air conditioner, water heater, or other types of major electrical equipment. Utilities cycle this equipment on and off during peak demand periods, usually in alternating 15 minute cycles. Utilities usually offer customers some type of rate discount as a participation incentive.

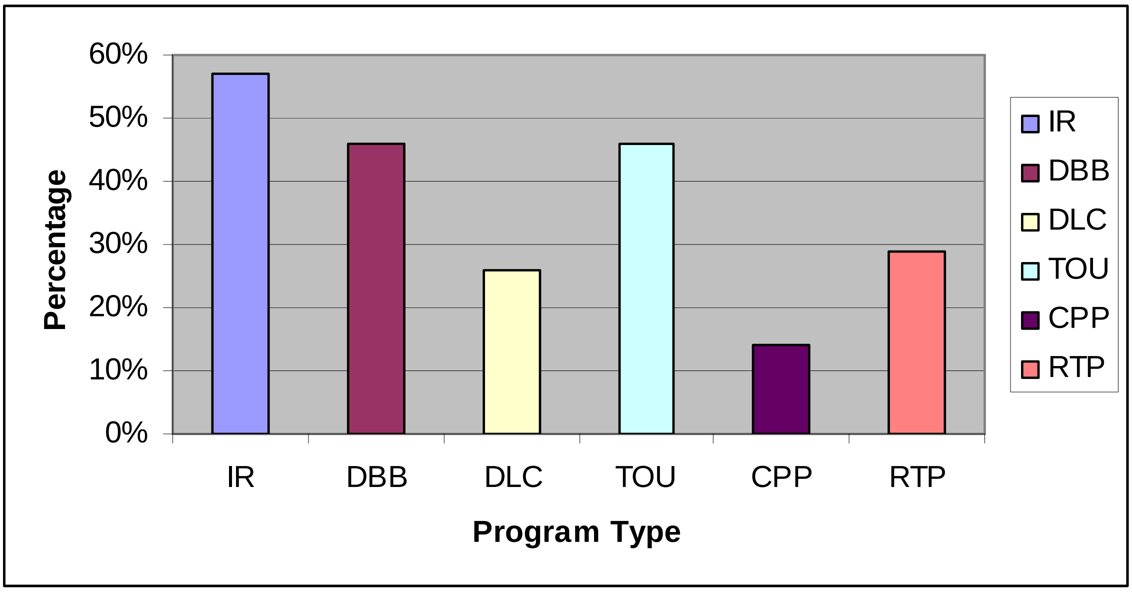
4. **Time-of-use (TOU) rates:** The most common type of TOU rates are "two-part" rates that charge customers a higher "on-peak" price than the standard "flat" utility rate during daytime hours, and a lower "off-peak" price during nighttime hours and weekends. Some utilities offer a "three-part" TOU rate, in which both the on-peak and off-peak periods are shorter than the typical two-part TOU rate periods, and also includes a "shoulder" period between the on-peak and off-peak hours, during which time prices are between the on-peak and off-peak prices.

5. **Critical peak pricing (CPP) rates:** These are similar to TOU rates, but add a "critical peak" period and rate. The "critical peak" period is usually 1% or fewer hours throughout the year, during which time the utilities' production or power purchase costs are highest. Electric prices during this period are higher than the regular TOU on-peak prices.

6. **Real-time pricing (RTP):** Prices offered through these programs are tied to some type of hourly pricing benchmark, such as the PJM RTP rate, or are based on the utilities' internally calculated short-term marginal costs.

About 80% of the utilities surveyed are conducting at least one type of DR program for C/I customers. The most common C/I DR programs, each offered by about half of the utilities surveyed, are interruptible rates, two-part TOU rates, and DBB programs. The next most common types of C/I DR programs, each offered by about one-fourth of the utilities surveyed, are DLC and RTP programs. Figure 5 below shows the percentage of utilities conducting each type of C/I DR program.

Figure 5. Percentages of Utilities Conducting Different Types of C/I DR Programs (N=40)



The percentage of traditionally regulated and restructured utilities that are offering each type of DR program are generally similar, with a few exceptions.

- Thirty percent of traditionally regulated utilities are operating commercial DLC programs, compared to just 8% of restructured utilities.

- Nineteen percent of traditionally regulated utilities are conducting commercial CPP programs, compared to no restructured utilities that are doing so.

- Fifty-nine percent of traditionally regulated utilities are offering IR programs, slightly more than the 46% of restructured utilities that are doing so.

- Twenty-six percent of traditionally regulated utilities are offering C&I RTP programs, somewhat less than the 38% of restructured utilities that are offering that type of DR program.

Most utilities started their interruptible rates programs in 1990 or earlier, as is the case for TOU rates. DBB and CPP programs all started within the past 5 years. C/I DLC and RTP programs are about evenly divided between those that started since 2000 and those that started in the mid-1990s or earlier.

2.3.1 Interruptible Rate Program Benchmarks

Interruptible rate programs provide the largest demand reduction impacts for about 80% of the utilities surveyed. About 17% of the utilities surveyed reported program impacts that amount to 15% or more of their C/I peak demands. However, most of these utilities report that most of their IR demand reduction impacts come from steel plants, which comprise a significant portion of these utilities' C/I peak demands.

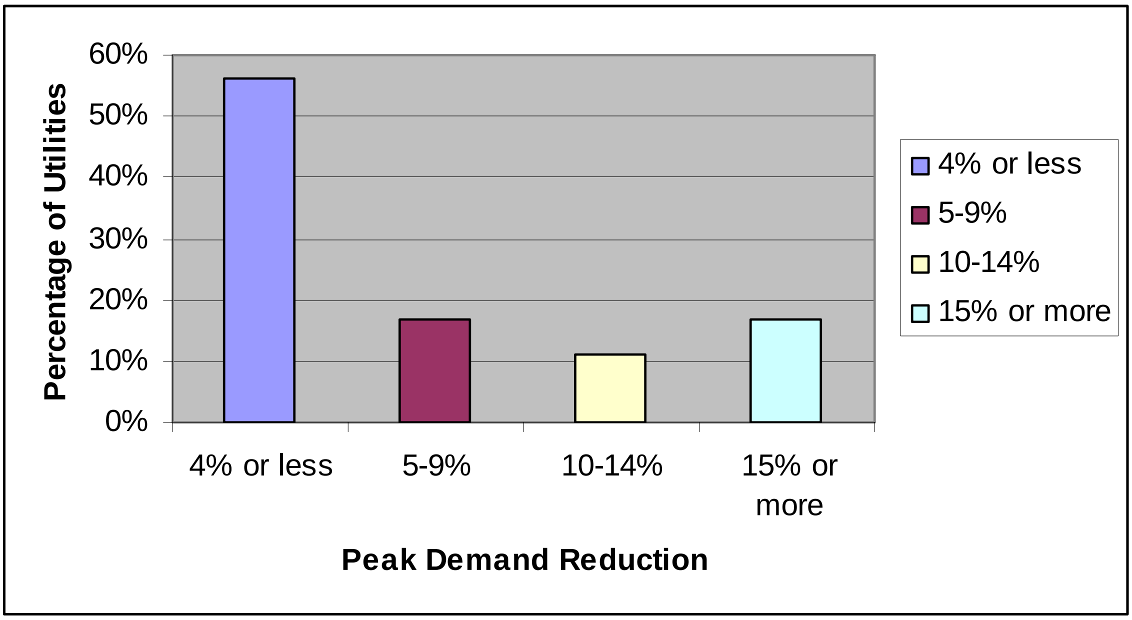
An additional 11% of utilities surveyed are able to reduce their C/I peak demands by 10-14% through their IR programs. These utilities have a broader base of program participation than most of the utilities with the largest program impacts.

So 10% of C/I peak demand reduction from IR programs is a reasonable benchmark that a variety of utilities with diverse C/I customer bases have achieved. By contrast, the largest group of utilities surveyed, about half of those providing data, can realize peak demand reductions of 4% or less of their C/I peak demands from their interruptible rate programs. The median IR program impact as a percentage of C/I peak demand for the utilities surveyed was 4%, while the corresponding mean was 7%. IR program impacts as a percentage of C/I peak demand for the utilities surveyed are shown in Figure 6 on the next page.

The most common characteristic of the top-performing IR programs was long program operating histories. The mean length of program operation for the top-performing programs is 24 years, and varied between 14 and 37 years. The overall mean number of years that all utilities surveyed have operated these programs is 17 years.

The largest impact IR programs are all being conducted by traditionally regulated utilities. The traditionally regulated utilities that are conducting IR programs have achieved a mean program impact of 9% of their C&I peak demands, compared to a mean impact of 3% of the restructured utilities' C&I peak demands. With the exception of one outlier, the mean operating IR program lifetime for the restructured utilities conducting IR programs is 13 years, about half of the mean program lifetime for the top-performing programs.

Figure 6. IR Program Demand Reduction Impacts, Percentage of Utilities' C/I Peak Demands (N=18)



The number of customers participating in the surveyed utilities' IR programs varied widely, but the highest participation rate reported was about 2% of the utilities' total number of C/I customers. The somewhat low participation rates are primarily due to the utilities' IR program eligibility requirements. Almost all utilities surveyed limit program eligibility to the utilities' larger customers. At the high end, a few utilities require participants to have a minimum peak demand of 5 MW or more, which has limited participation to 10-20 customers even for some of the top-performing programs. On the low end, several utilities allow customers who can reduce their peak demands by as little as 50 kW to participate in their IR programs. These utilities have hundreds or thousands of program participants. The median number of IR program participants for the utilities surveyed is 20, while the mean number of program participants is 212.

Given the wide variation in program eligibility requirements and number of participating customers, there was also a wide variation in program impacts per participating customer. Program impacts per participating customer varied from 187 kW/customer for the utility with the largest number of program participants, up to 26,000 kW/customer for one of the utilities that restricts program eligibility to its largest customers. The median program impact per participating customer is 2,000 kW of demand reduction.

2.3.2 Demand Bidding/Buyback Program Benchmarks

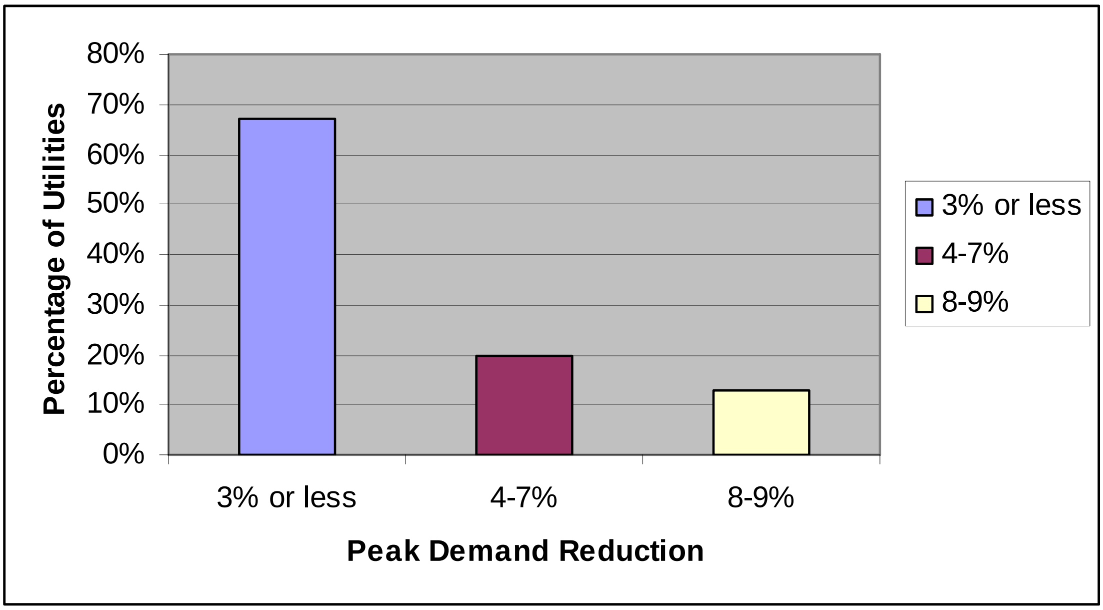
DBB programs are estimated to provide the largest peak demand impacts for about 20% of the utilities surveyed, and several additional utilities also estimate significant demand reduction impacts from their DBB programs. The top-performing programs have impacts that amount to 8-9% of utilities' C/I peak demands. Utilities achieved the reported magnitude of impacts several years ago when spot market electric prices were higher than they have been in recent years.

It should also be noted that most of the utilities conducting DBB programs have not used them much or at all in the past several years given the low spot market electric prices of this time. So DBB program impacts are more uncertain than those for other DR programs that have been used more regularly. Since the load reduction incentives that utilities offer customers through DBB programs are usually tied to spot market electric prices, high spot market electric prices are needed to achieve the demand impacts reported by the utilities.

The top-performing DBB programs' impacts of 8-9% of C/I peak demands should be considered benchmarks for DBB programs only for high spot market electric price periods. During lower electric price periods, the demand impacts realized by these programs will likely be much lower.

The top-performing programs are conducted by 13% of the utilities surveyed that are conducting such programs. By contrast, 67% of the utilities surveyed that are conducting DBB programs report demand reduction impacts of 3% of their C/I peak demands or less, while 20% of the utilities surveyed report program impacts of 4%-7% of their C&I peak demands. The mean and median program impacts are 3% and 1% respectively of the surveyed utilities' C/I peak demands. The DBB program impacts as a percentage of the utilities' C/I peak demands are shown in Figure 7, below.

Figure 7. DBB Program Impacts, Percentage of Utilities' C/I Peak Demands (N=15)



The largest impact DBB programs have few common characteristics, other than having less than one-tenth of one percent of its C/I customers participating in the programs. It is interesting to note that both of these utilities achieve larger DR impacts from their IR programs than they do from their DBB programs. Since DBB programs are of relatively recent vintage, the oldest having been introduced in 1998, utilities may achieve larger impacts from these programs in the future, especially if the high spot market electric prices that gave rise to DBB programs return on a regular basis.

Both of the largest impact DBB programs are operated by traditionally regulated utilities. One utility (ComEd) operating in a restructured state, Illinois, achieved DBB program impacts of 5% of their C/I peak demand, placing it in the second largest impact group of utilities.

2.3.3 Other C/I DR Program Benchmarks

Only one utility surveyed, Otter Tail Power Company, reported DLC program impacts that were larger than 1% of their C/I peak demands. Otter Tail's DLC program impacts total about 9% of their C/I peak demand. Otter Tail operates several C/I DLC programs, as they do for their residential customers, but about two-thirds of their total DLC program impacts come from their controllable space heating program.

Otter Tail has been conducting its C/I DLC programs for 25 to 60 years, and currently has almost 20% of its C/I customers participating in its C/I DLC programs. The company's success with its DLC programs illustrates what is possible to achieve through these types of programs, but for other utilities to achieve similar results would likely require many years of vigorous program operation.

Utilities reported very limited demand reduction estimates for TOD, CPP, and RTP rate programs. Only one utility surveyed, Georgia Power, reported demand reduction impacts from these programs that were greater than 1% of the utilities' C/I peak demands. Georgia Power offers two related RTP programs to its customers. Their total combined RTP peak reduction impacts are approximately 8% of the company's C/I peak demand. Other utilities that the project team was not able to survey as part of this project also report significant program impacts from RTP programs[1].

Georgia Power's success with its RTP programs illustrates what is possible to achieve through these types of programs. However, what is not clear is the replicability of its success at other utilities.

3. CUSTOMER SURVEY APPROACHES

3.1 Introduction

This section will discuss customer survey approaches to estimate DR potential. The focus of this section will be on telephone surveys, as this particular survey approach has been used most often in practice to estimate DR potentials. In theory, utilities could use mail surveys, in-person interviews, or detailed on-site equipment surveys to estimate DR potential. However, the customer survey research reviewed by the project team that was primarily done to estimate DR potential almost all used telephone surveys for that purpose.

The telephone survey approach primarily used to estimate DR potentials represent a different approach than the on-site survey approaches that are primarily used to estimate EE potentials. EE potential is usually estimated for each DSM measure that a utility includes in its DSM programs, or is considering for future programs. Given that approach, most EE potential studies collect detailed data on the current saturations of EE measures, as well as the saturations of standard efficiency equipment that EE measures could replace in the future.

However, the detailed on-site survey approach often used for EE potential studies is a rather expensive method to conduct such studies. Comprehensive EE potential studies that use this approach often cost $1 million or more to complete. This budget barrier has been a significant obstacle to using the on-site survey approach to conduct DR potential studies.

Customer telephone surveys can provide very useful inputs for DR potential estimates. Customer surveys usually provide the best estimates for a variety of DR potential parameters such as:

- Customers' awareness of existing DR programs, and how well they understand the programs overall, as well as individual program components.
- Customer perceptions about the importance of electricity costs, reliability, or other electric matters, and how receptive they are to changing the manner in which they have historically used electricity.
- The extent to which customers have evaluated participating in existing DR programs, and made decisions about whether or not to participate in them.
- The magnitude of various market barriers that impede customers from participating in DR programs, and customers' ideas about how best to overcome such barriers.
- Saturations of equipment that are important components of DR programs. These can include central air conditioners, water heaters, electric heaters, and pool pumps for

[1] See, for example, Goldman et al, "A Survey of Utility Experience with Real Time Pricing", Lawrence Berkeley National Laboratory, December 2004.

direct load control programs. Commercial and industrial customers' back-up generators, energy management systems, and other types of control equipment are also important enabling technologies for a variety of DR programs.

Customer surveys are not that reliable for estimating DR peak electric reduction impacts per customer. Most customers will not know how much they could reduce their electric loads, particularly their peak period electric loads, in response to utility price incentives or control schemes. Some customers who have thoroughly evaluated participating in a DR program will be able to provide such estimates, but such customers are usually the minority of program non-participants. How representative such customers are of other customers who have not conducted such internal DR impact estimates is usually uncertain. Pilot program or full-scale program impact results will usually provide better estimates of program impacts per customer than customer survey results.

3.2 Sample DR Potential Survey Instruments

This section will discuss three sample DR potential survey instruments. Two are for direct load control programs, one for residential customers and a second for small business customers. The residential DLC survey instrument is presented at the end of this section, and the small business customers DLC survey instrument can be found in Exhibit B. These DLC survey instruments are intended for program planning purposes, or for utilities that recently started a DLC program. The primary purposes of these surveys are to estimate the saturations of equipment that could be covered by a direct load control program, such as central air conditioners, electric water heaters, electric heating systems, and pool equipment, as well as some information about how customers currently operate such equipment. Demographic and firmographic questions are also included in these surveys to provide data for program target marketing purposes.

Questions are also included on customers' interest in DLC programs, and the participation incentives that they would require. However, customer responses to such questions must be used cautiously, especially in situations in which the utility has not yet started the DLC program. Customers' responses to such hypothetical questions will provide some indications about their interest in participating in a DLC program, but such responses should not be interpreted as exact estimates of their likely future program participation. Many studies have shown that customers' actual purchase decisions are often different than their stated purchase intents.

The third sample customer survey provided was developed by Quantum Consulting (QC) and Summit Blue Consulting (SBC) for an evaluation of California's DR programs for commercial and industrial (C/I) customers with demands of 200 kW or greater. This survey was implemented with a sample of program non-participants, and was used for other purposes in addition to estimating DR potential. The two main programs that this survey was designed to evaluate were critical peak pricing (CPP) and demand bidding (DBB), which were described in the previous section of this report. In addition, the survey covered an hourly pricing option (HPO) that was offered by one of the three largest California utilities.

3.3 Using Survey Results to Estimate DR Potentials

There are a number of methods for using customer survey results to estimate DR potentials. To follow through with the residential DLC survey example, the steps to follow for applying the survey results would be:

1. Apply the appropriate weights to each survey completed and tabulate the results.

2. Estimate the saturations for the appliances of interest, such as central air conditioners, in the utility's customer population.

3. Use a separate estimate for program impacts per participating customer. Sources for such estimates can include the utility's DR pilot program estimates, or the program results from another utility in a similar climate zone.

4. The product of number of (for example) central air conditioners in a utility's area and the DR impact per air conditioner equals the technical potential for cycling air conditioners.

5. A somewhat conservative estimate of market potential can be obtained from the survey results for the percentage of customers who responded that they would "definitely" be interested in participating in the DLC program. This conservative market potential estimate is calculated as the product of the technical potential estimate and the percentage of customers who would "definitely" be interested in participating in the DLC program.

6. A somewhat optimistic estimate of market potential can be obtained by adding the percentage of customers who responded to the survey that they would be interested in participating at the levels of incentives planned for the DLC program.

7. The above estimates of market potential should be compared to the DLC program benchmarks presented in section two of this report. The impact estimates should be compared to the 10% of residential peak demand benchmark proposed in that section for residential DLC programs. The customer participation percentages from the survey results should also be compared to the 29%-56% results from the best performing programs.

Customer survey results have most often been reported to overestimate the rates of actual customer participation in DSM programs. However, comparing the survey results to actual top-performing program results can also ensure that the estimated participation rates are not too conservative.

As part of the California DR survey discussed previously, an alternative approach to using the survey results to estimate DR potentials was used. For that project, C/I customers were asked directly to estimate how much they might be able to reduce their peak demands if they were to participate in a CPP or DBB program. Customers were also asked about their likelihood to participate in one of the current DR programs in the future. The product of these two sets of responses was used to estimate DR potentials among this group of customers, with the understanding that the resulting DR potential estimates are rough approximations of DR potential.

The energy crisis in California and the utilities' aggressive implementation of demand side programs for many years there has significantly increased customers' energy awareness. Therefore, California electric customers, particularly the larger C/I customers covered by this survey, are more likely to have evaluated how much they could reduce their load to participate in a DR program than most groups of customers in other locations.

The executive summary from this California evaluation report is presented first in Exhibit C, followed by the survey instrument in Exhibit D.

4. DEMAND RESPONSE POTENTIAL MODELING APPROACHES

4.1 Introduction

This section will discuss different types of computer modeling approaches that have been used to estimate demand response (DR) potentials. The computer models and modeling approaches that have been used to estimate DR potentials have generally been rather different than those used to estimate energy efficiency (EE) potentials. As discussed previously in the survey approaches section, customer surveys done to estimate EE potentials are primarily detailed on-site surveys of customers' homes and businesses. Such surveys provide estimates for the current saturations for a wide variety of EE measures and corresponding standard efficiency equipment. Many EE potential models rely on such rich data sets for accurate estimates of the applicable market sizes for EE measures, as well as to calibrate the models to current EE measure saturations.
Several consulting firms with computer models for forecasting EE potential tried to use them to forecast DR potential, but found that they were not that effective for doing so. These firms often developed different computer models or approaches to estimate DR potentials. Examples of issues that arose when trying to use EE potential forecasting models for DR potential purposes included:

- One EE potential model using the customer paybacks of EE measures as a significant input to market potential estimates. However, many utilities do not require customers to make any initial investment to participate in their DR programs. Customers' DR program participation costs are often the company's staff time to reduce their electric loads during peak demand periods, or a reduction in personal comfort during such times. Such costs are much more difficult to quantify than estimating the incremental cost of an EE measure, and many utilities have not tried to estimate such costs. Many utilities just treat such costs as zero when conducting their program benefit-cost analyses.

- Another EE potential model is a variant of an end use forecasting model, and so was designed to forecast electric kWh sales, not peak demands. Making the translation between forecasting energy and demand proved problematic, so the consulting firm developed a separate DR potential spreadsheet model.

The most common method of estimating EE potentials is often described in an abbreviated way as a "bottom-up" approach. This is because the EE potential estimates are based on converting various numbers of standard efficiency equipment in each customer market segment or sector. Total EE potential estimates for a given utility are developed by aggregating the number of measures converted across market segments, as well as their corresponding energy savings, demand savings, and costs. This is in contrast to some high-level approaches to demand side potential estimates that use generalized market-wide "top-down" assumptions to estimate potential.

DR potential approaches generally use bottom-up approaches, as is done for EE potential studies. Customer participation in DR programs often varies widely between market segments, so using one assumption for an entire commercial/industrial market sector, for example, would not result in the most accurate estimate. The DR potential estimation approaches discussed in more detail later in this section use a two or three step process to estimate DR potentials.

Allocate the utility or state's electric energy sales and peak demand to its most significant market segments, or to market sectors such as residential, commercial, and industrial. This is usually done using the utility's existing information on its sales and peak demands by market segment. As part of this initial step, load duration curves are sometimes developed for each market segment or sector.

1. Allocate the utility's sales and peak demands for each market segment/sector to end use categories, or at least to the end uses that are covered by the DR program(s) under consideration. This allocation is done either using the utility's existing information, and/or the expert judgments of its staff or consultants. This step is sometime omitted depending on the DR program under consideration or due to lack of good end use data.
2. Estimate DR potentials for the DR strategies or programs of interest based on a variety of data sources or methods, such as:
    a. Using the actual results of the given utility's DR programs or top-performing DR program(s) from other utilities that are similar to those under consideration. Computer models developed to estimate the DR program impacts for the comparison programs are sometimes used to generate utility-specific results.
    b. Economic analyses of the DR measures under consideration.
    c. Expert judgments on either the applicability of certain DR programs to various market segments, or feasible participation rates for each program of interest.

Summaries of three examples of these approaches can be found in Exhibits E, F, and G. Capsule summaries are provided below:

1. The first is a study on the DR potential for C/I RTP programs in California by Christensen Associates. This study applied the results of econometric analyses of Georgia Power's successful RTP programs to California's C/I customers. This approach can work well when rich data sets from program impact evaluations are available, but such situations are somewhat rare.
2. The second is a description of a software tool called DRPro developed by Quantec LLC. This tool uses a more generalized approach to estimating DR potentials. It works best with capacity-based DR programs, but has been used for energy-based DR programs as well.
3. A Delphi approach that used a Bass Diffusion Curve done by KEMA-XENERGY for estimating the potential for Time-of-Use Rates for Southern California Edison. This approach relied on a panel of experts to estimate several DR forecasting model parameters that were uncertain.

Complete reports from these projects will be posted on the project portal.

CHAPTER 6 EXHIBITS

SURVEY FORMS

EXHIBIT A: UTILITY DEMAND RESPONSE PROGRAM SURVEY

Organization ____
Contact Person ____
Title ____
Phone # ____
E-mail address ____
Survey date ____

5. INTRODUCTION

1. Is your company conducting DR programs?
   a) Yes (skip to #3)
   b) No

2. Why isn't your company conducting DR programs?
   a) Tried them in the past and found they were not cost effective
   b) Tried them in the past and found that customers were not interested
   c) Company has excess capacity and does not need to reduce peak demand
   d) Other: ____

6. RESIDENTIAL DR PROGRAMS (IF OFFERED)

3. I want to start by asking about your company's residential DR programs. What types of residential DR programs is your organization conducting, if any? What are the program names?
   a) No residential DR programs
   b) DLC: ____
   c) TOU rates: ____
   d) CPP: ____
   e) RTP: ____
   f) Other ____

4. About what year did these programs start?
   a) Direct load control: ______________
   b) Time-of use rates: _______________
   c) Critical Peak Pricing: _____________
   d) Real-Time Pricing: _______________
   e) Other ____

5. What are the eligibility criteria for these programs? (Could be location, equipment ownership, or other factors.)
   a) Direct load control: ____
   b) Time-of use rates: ____
   c) Critical Peak Pricing: ____
   d) Real-Time Pricing: ____
   e) Other ____

6. How do you primarily market the programs to customers?
   a) Direct mail
   b) Bill inserts
   c) Telemarketing
   d) Other ____

7. What is the program pricing structure and when are the different prices in effect?
   a) DLC rate discount: ____
   b) Critical peak price: ____
   c) Regular on-peak price: ____
   d) Shoulder period price: ____
   e) Off-peak price: ____
   f) Hourly prices: ____

8. What are your company's average residential summer and winter rates per kWh?
   a) Summer: _________________________
   b) Winter: ___________________________

9. Does your company provide special load control equipment to help customers manage their loads, or do customers do so on their own?
   a) Load control equipment provided by utility: __________________________
   b) Load control equipment purchased by customer: ______________________
   c) Customers reduce their loads manually

10. How are customers' loads monitored for this program?
    a) Interval data recorder paid for by utility
    b) Most customers loads are not monitored, just controlled by utility
    c) Other____

11. How is load monitoring/recording equipment read?
    a) Manually by a utility meter reader
    b) Through a phone connection paid for by the utility
    c) Through a phone connection paid for by customers

d) Power line carrier or other wireless method
e) Other: ____

12. About how many customers are currently participating in your DR programs?
a) DLC ____
b) TOU rates____
c) CPP rates____
d) RTP rates____
e) Other ____

13. About how many residential customers does your company have, and how many are eligible for DR programs?
a) Total residential: ________________________________
b) Eligible for DR programs: _________________________

14. About how much peak load reduction do you realize from your DR programs?
a) DLC: ____
b) TOU rates: ____
c) CPP rates: ____
d) RTP rates: ____
e) Other: ____

15. How does your company determine the amount of load that individual customers reduce during a peak period or load reduction period?
a) Analysis of household hourly electric loads
b) Analysis of CAC hourly electric loads
c) CAC running time metering analysis
d) Monthly billing data analysis
e) Only calculate peak demand reductions of customer groups/classes.
f) Other____

16. Approximately what is your company's annual peak demand, when does it occur, and about what percent of the total peak do residential customers cause?
a) Annual peak demand and season: _________________________________
b) Approximate residential percent of peak: ___________________________

17. Is your company trying to expand these programs, or are they in maintenance mode, or are they in decline/been discontinued? Why?
a) DLC: ____
b) TOU rates: ____
c) CPP rates: ____
d) RTP rates: ____
e) Other: ____

18. Has your company tried to estimate the long-term market potential for these programs, and if so, how? Are the results available?
a) Yes: ____
b) No

19. What type of benefit-cost analysis does your company do for these programs?
a) Class cost of service studies: ___________________________________
b) DSM style B/C analysis: ____

c) Other: ____

d) Little/no B/C analysis: ____________________________________

20. What models, if any, does your company use for DR benefit-cost analysis?
    a) Class COS model: ______________________________________
    b) Production cost model: __________________________________
    c) DSManager or similar: ___________________________________
    d) Other: ____
    e) No formal computer model: _______________________________

21. How does your company incorporate DR programs into long-term system planning?
    a) Include in IRPs. Last filed: _____________
    b) Include in generation planning/certificates of need. Last filed: ________
    c) Not included in system planning
    d) Don't know/confidential

22. How satisfied are you with each of the following aspects of the program on a scale of 1-5, where 5 is very satisfied and 1 is very dissatisfied?

a.	Ease of signing customers up	1	2	3	4	5
b.	Pricing/discount amounts	1	2	3	4	5
c.	Load reduction procedures/estimates	1	2	3	4	5
d.	Billing and payments	1	2	3	4	5
f.	Customer relations	1	2	3	4	5

23. If you could start over from scratch, how would you re-design the programs/rates?

____

____

____

7. RESIDENTIAL CONCLUSION

24. Are your Company's residential DR programs described in detail on your organization's web site, in a report of some type, or by brochures on the programs?
    a) Web site: address ____________________________________
    b) Report: type ____
    c) Brochures
    d) None of the above

8. COMMERCIAL/INDUSTRIAL/INSTITUTIONAL DR PROGRAMS

Contact info, if different than residential contact:

Contact Person ____

Title ____

Phone # ____

E-mail address ____

Survey date ____

25. What types of CII DR programs is your organization conducting? What are the program names?
    a) Interruptible rates: ____
    b) Direct load control: ____
    c) Time-of use rates: ____
    d) Critical Peak Pricing: ____
    e) Real-Time Pricing: ____
    f) Demand Buy Back (Voluntary): ____________________________________
    g) Demand Buy Back (Mandatory): ___________________________________
    h) Other ____

26. About what year did these programs start?
    a) Interruptible rates: ________________
    b) Direct load control: ________________
    c) Time-of use rates: _________________
    d) Critical Peak Pricing: ______________
    e) Real-Time Pricing: ________________
    f) Demand Buy Back: ________________
    g) Other ____________________________

27. What are the eligibility criteria for these programs? (Location, minimum demand reduction, equipment ownership, or other factors)
    a) Interruptible rates: ____
    b) Direct load control: ____
    c) Time-of use rates: ____
    d) Critical Peak Pricing: ____
    e) Real-Time Pricing: ____
    f) Demand Buy Back: ____
    g) Other ____

28. How do you primarily market the programs to customers?
    a) Contact by account reps
    b) Direct mail
    c) Telemarketing
    d) Other ____

29. What is the program pricing structure and when are the different prices in effect?
    a) IR rate discount: ____
    b) DLC rate discount: ____
    c) Critical peak price: ____
    d) Regular on-peak price: ____
    e) Shoulder period price: ____
    f) Off-peak price: ____
    g) Hourly prices: ____

30. What are your company's average CII summer and winter rates?
    a) Summer: ________________________
    b) Winter: __________________________

31. Does your company provide any special load control equipment to help customers manage their loads, or do customers do so manually/with their own equipment?
    a) Load control equipment provided by the utility______________________
    b) Customers reduce their loads with EMS systems or manually
    c) Customers use on-site generators to reduce loads
    d) Other: ____

32. How are customers' electric loads monitored for this program?
    a) Interval data recorder paid for by utility
    b) Interval data recorder paid for by customers
    c) Other____

33. How is load monitoring/recording equipment read?
    a) Manually by a utility meter reader
    b) Through a phone connection paid for by the utility
    c) Through a phone connection paid for by customers
    d) Power line carrier or other wireless methods

34. About how many customers are currently participating in these programs?
    a) Interruptible rates: ____
    b) Direct load control: ____
    c) Time-of use rates: ____
    d) Critical Peak Pricing: ____
    e) Real-Time Pricing: ____
    f) Demand Buy Back (Voluntary): _________________________________
    g) Demand Buy Back (Mandatory): ________________________________
    h) Other ____

35. About how many CII customers does your company have, and how many are eligible for DR programs?
    a) Total CII customers: _________________________________
    b) Eligible for DR programs: __________________________

36. About how much peak load reduction do you realize from your DR programs?
    a) Interruptible rates: ____
    b) Direct load control: ____
    c) Time-of use rates: ____
    d) Critical Peak Pricing: ____
    e) Real-Time Pricing: ____
    f) Demand Buy Back: ____
    g) Other ____

37. What is the ratio of actual to expected load reductions for these programs (realization rates)?
    a) Interruptible rates: ____
    b) Direct load control: ____
    c) Time-of use rates: ____
    d) Critical Peak Pricing: ____
    e) Real-Time Pricing: ____
    f) Demand Buy Back: ____

g) Other ____

38. How does your company determine the amount of load that individual customers reduce during a peak period or load reduction period?
    a) Analysis of hourly electric loads
    b) Difference in load on peak days before, during, and after the peak period.
    c) Difference in load on peak days/times versus recent non-peak days/times.
    d) Do not calculate peak demand reductions of individual customers
    e) Other____

39. Approximately what is your company's annual peak demand, when does it occur, and about what percent is caused by CII customers?
    a) Annual peak demand and season: ___________________________
    b) Approximate CII percentage of system peak: ____________________

40. Is your company trying to expand these programs, or are they in maintenance mode, or are they in decline/been discontinued? Why?
    a) IR: ____
    b) DLC: ____
    c) TOU rates: _______________________________________
    d) CPP rates: _______________________________________
    e) RTP rates: _______________________________________
    f) DBB: ____
    g) Other: ____

41. Has your company tried to estimate the long-term market potential for these programs, and if so, how? Are the results available?
    a) Yes: ____
    b) No
42. What type of benefit-cost analysis does your company do for these programs?
    a) Class cost of service studies: ___________________________
    b) DSM style B/C analysis: ________________________________
    c) Other: ____
    d) Little/no B/C analysis: _________________________________

43. What models, if any, does your company use for DR benefit-cost analysis?
    a) Class COS model: ____________________________________
    b) Production cost model: _________________________________
    c) DSManager or similar: _________________________________
    d) Other: ____
    e) No formal computer model: ______________________________

44. How does your company incorporate DR programs into long-term system planning?
    a) Include in IRPs. Last filed: ________________
    b) Include in generation planning/certificates of need. Last filed: _________
    c) Not included in system planning
    d) Don't know/confidential

45. How satisfied are you with each of the following aspects of the programs on a scale of 1-5, where 5 is very satisfied and 1 is very dissatisfied?

a.	Ease of signing customers up	1	2	3	4	5
b.	Pricing/discount amounts/process	1	2	3	4	5
c.	Load reduction procedures/estimates	1	2	3	4	5
d.	Billing and payments	1	2	3	4	5
f.	Customer relations	1	2	3	4	5

46. If you could start over from scratch, how would you re-design the programs/rates?
____
____
____
____
____

9. CII DR PROGRAMS CONCLUSION

47. Are your Company's CII LM programs described in detail on your organization's web site, in a report of some type, or by brochures on the programs?
    a) Web site: address ____
    b) Report: type ____
    c) Brochures
    d) None of the above

****End of Exhibit A***

EXHIBIT B: SMALL BUSINESS DLC DR POTENTIAL TELEPHONE SURVEY

Customer Name ____
Respondent ____
Address ____
City, State, Zip code ____
Phone # ____
E-mail address (if any) ____
Survey date ____

<u>Introduction</u>

We are calling on behalf of Utility XYZ about a potential new energy management program that your company could be eligible for. We would like to ask you a few questions about your business, energy using equipment, and interest in this potential new energy program. This survey will take about 10-15 minutes to complete.

10. COMMERCIAL AIR CONDITIONING SYSTEM INFORMATION (DELETE THIS SECTION IF AIR CONDITIONERS ARE NOT BEING CONSIDERED FOR INCLUSION IN THE PROGRAM.)

1. I'll start by asking about your company's air conditioning system. Which of the following types of air conditioning systems serves your business, if any?
    a. "Rooftop" or ground-mounted unitary electric AC system
    b. Natural gas central AC
    c. Electric heat pump
    d. Building cooling system that serves multiple business
    e. Window or room air conditioners. How many? ________________
    f. Evaporative coolers
    g. Other (specify)____
    h. No AC system of any type (skip to #6)
    i. Don't know

2. About how many air conditioning units serve your business?
    a. 1-2
    b. 3-5
    c. 6-10
    d. 11 or more
    e. Don't know

3. About how old is your average air conditioner?
    a. 1-2 years
    b. 3-5 years
    c. 6-10 years
    d. 11-20 years
    e. More than 20 years
    f. Don't know

4. How do you operate your air conditioner during working hours (8 am to 6 pm)?
    a. Set the thermostat to about ______ degrees
    b. Set the control switch to "on" and let it run
    c. Only run the AC on hot days. About how many days per month? _____
    d. Shut it off most of that time
    e. Other (specify) ____

5. How do you operate your air conditioner during evening and nighttime hours?
    a. Set the thermostat to about ______ degrees
    b. Set the control switch to "on" and let it run
    c. Only run the AC on hot days. About how many days per month? _____
    d. Shut it off most of that time
    e. Other (specify) ____

11. HEATING SYSTEM INFORMATION (DELETE THIS SECTION IF ELECTRIC HEATING SYSTEMS ARE NOT BEING CONSIDERED FOR INCLUSION IN THE PROGRAM.)

6. Next I want to ask about your company's main heating system. Does the main heating system serve only your business or other businesses as well?
   a. Heating system serves only this business
   b. Heating system serves multiple businesses
   c. No heating system serves the business (skip to # 12)
   d. Don't know

7. What type of fuel does your heating system use? (Check all that apply)
   a. Electricity
   b. Natural gas (skip to #12)
   c. Propane (skip to #12)
   d. Oil (skip to #12)
   e. Don't know (skip to #12)
   f. Other (specify): ___________________________________(skip to #12)

8. Which of the following best describes your electric heating system?
   a. Central forced air furnace
   b. Central furnace with hot water heat distribution
   c. Radiant heaters
   d. Air source heat pump
   e. Ground source heat pump
   f. Individual baseboard heaters located near the floor
   g. Individual wall heating units with fans
   h. Boiler
   i. Portable heaters
   j. Other (specify)____

9. About how old is your heating system?
   a. 1-2 years
   b. 3-5 years
   c. 6-10 years
   d. 11-20 years
   e. More than 20 years
   f. Don't know

10. How do you operate your heating system during working hours (8 am to 6 pm)?
    a. Set the thermostat to about ______ degrees
    b. Set the control switch to "on" and let it run
    c. Only run it on cold days. About how many days per month? _____
    d. Shut it off most of that time
    e. Other (specify) ____

11. How do you operate your heating system during evening and nighttime hours?
    a. Set the thermostat to about ______ degrees

b. Set the control switch to “on” and let it run
c. Only run it on cold days. About how many days per month? _____
d. Shut it off most of that time
e. Other (specify) ____

12. Hot Water Heater Information (Delete this section if hot water heaters are not being considered for inclusion in the program.)

13.

12. Next I want to ask about your business’ hot water heater. Does your water heater serve only your company or other businesses as well?
    a. Hot water heater serves only this business
    b. Hot water heater serves multiple businesses
    c. No hot water heater serves the business (skip to # 16)
    d. Don’t know
    e. Other (specify)____

13. What type of fuel does your water heater use?
    a. Electricity
    b. Natural gas (skip to #16)
    c. Propane (skip to #16)
    d. Oil (skip to #16)
    e. Don’t know (skip to #16)
    f. Other (specify): ____________________________________(skip to #16)

14. Is your hot water heater a regular stand-alone tank/system, or another type of system?
    a. Stand-alone tank/system (standard water heater)
    b. Tankless “instantaneous” hot water heater
    c. Heating system furnace also heats hot water
    d. Other (specify)____

15. About how old is your water heater?
    a. 1-2 years
    b. 3-5 years
    c. 6-10 years
    d. 11-20 years
    e. More than 20 years
    f. Don’t know

14. Swimming Pool Information (Delete this section if pool pumps or pool heating equipment is not being considered for inclusion in the program.)

16. Does your business have a swimming pool at this location?

a. Yes
b. No (skip to # 20)

17. Is the swimming pool heated?
    a. Yes
    b. No (skip to #19)

18. What type of fuel does the swimming pool heater use?
    a. Electricity
    b. Natural gas
    c. Propane
    d. Oil
    e. Don't know
    f. Other (specify): ___________________________________

19. Does your swimming pool have a pump that circulates the water?
    a. Yes
    b. No

15. Interest in Direct Load Control Program (Skip if no ownership of major electrical equipment previously asked about)

20. Utility XYZ is considering starting an energy management program for businesses like yours that would include a rate discount or free programmable thermostat (depending on the utility's plans). To qualify for this program, you would agree to allow the utility to cycle your AC, water heater or other major electrical equipment on very hot/cold "peak demand" days. This cycling would not harm your electrical equipment or cause much of a change in the temperature of your business. Would you be interested in participating in such a program?
    a. Definitely yes
    b. Depends of the amount/type of incentive offered
    c. Definitely no
    d. Other response: ____
    e. Don't know
21. Would receiving a free programmable thermostat that's installed for you be sufficient incentive to sign up for such a program?
    a. Yes (Skip to # 23)
    b. No
    c. Don't know

22. About how much of an annual rate discount would you require to sign up for such a program? Would you require a…
    a. 5%-15% reduction in your summer/winter electric bill
    b. 16%-30% reduction in your summer/winter electric bill
    c. More than a 30% reduction in your summer/winter electric bill
    d. Other response: ____
    e. Don't know

16. Business and Facility Information

23. Which of the following business /facility type best describes your organization?
    a. Office—financial, insurance, real estate, legal, consulting
    b. Office—government or other
    c. Retail store
    d. Grocery store
    e. Restaurant
    f. Warehouse/wholesale
    g. Health care
    h. Education
    i. Lodging
    j. Other commercial (specify) ______________________________________
    k. Manufacturing (specify type) ______________________________________

24. Does your company own your building or do you rent it?
    a. Own or buying
    b. Rent or lease
    c. Other (specify) ____

25. Is this facility usually occupied year-round, or only part of the year?
    a. Occupied year-round
    b. Occupied just during the __________________ season
    c. Occupied just on weekends or for vacations

26. About how large is this facility?
    a. Less than 5,000 square feet
    b. 5,000-9,999 square feet
    c. 10,000-19,999 square feet
    d. 20,000-29,999 square feet
    e. 30,000 square feet or more
    f. Don't know

27. About what year was this facility constructed?
    a. 1949 or earlier
    b. 1950-1969
    c. 1970-1979
    d. 1980-1989
    e. 1990-1999
    f. 2000 or more recently
    g. Don't know

28. How many people work in this business?
    a. _____ Number of full-time employees
    b. _____ Number of part-time employees

29. What category best describes the business' total annual revenues at this location?

a. Less than $1 million
b. $1 million to 5 million
c. $6 million to 10 million
d. $11 million to 20 million
e. Over $20 million

End of Exhibit B

EXHIBIT D: WORKING GROUP 2 FINAL QUANTITATIVE CUSTOMER SURVEY INSTRUMENT

INTRODUCTION

SCREEN1

[WHEN RECEPTIONIST ANSWERS]:

[LARGE COMPANY]: May I have Plant Engineering, please?
[SMALL COMPANY]: May I speak with the Facilities Manager, please?

[OTHER DEPARTMENTS TO ASK FOR]:

Maintenance	General Services
Operations (Manager)	Public Relations
Plant Services	Purchasing
Building Manager	Planning Department

LEAD IN
INTRO1

Hello, this is ______________________, calling from Quantum Consulting on behalf of the California Public Utilities Commission and [UTILITY]. We are conducting a study on issues related to energy usage and peak power demand in California. May I speak with the person in your organization who is responsible for energy-related decisions for this facility?

-

[IF NEEDED:] This is a fact-finding survey only – we are NOT selling anything, and responses will not be connected with your firm in any way. The Public Utilities Commission wants to better understand how businesses think about and manage their summer peak energy usage. Your input is very important to the Commission.

1	Yes	INTRO2_2
2	Respondent not available now	CALL BACK
3	Respondent coming to phone	INTRO2_1
4	No such person	INTRO1A
88	Refused	INTRO1A

-

-

INTRO1A

[IF NO SUCH PERSON]: May I speak with the person in your organization who is responsible for decisions regarding construction, renovation, or operation of your physical facilities?

INTRO1B NAME OF CONTACT: ____

INTRO1C TITLE: ____

IF RESPONDENT IS NOT AVAILABLE, GET HIS/HER NAME AND TITLE; MAKE ARRANGEMENTS TO CALL LATER

INTRO2_1

WHEN RESPONDENT GETS ON THE LINE: Hello, this is _______________________, calling from Quantum Consulting on behalf of the Public Utilities Commission and [UTILITY]. We are conducting a study on issues related to energy usage and peak power demand in California. Are you familiar with your organization's energy-related decisions such as those concerning your utility rate and energy usage?

1	Yes	INTRO3
2	No	INTRO2A

INTRO2_2

WHEN RESPONDENT GETS ON THE LINE: We are conducting a study on behalf of the Public Utilities Commission and [UTILITY] on issues related to energy usage and peak power demand in California. Are you familiar with your organization's energy-related decisions such as those concerning your utility rate and energy usage?

1	Yes	INTRO3
2	No	INTRO2A

INTRO2A

Who would be the best person in your organization to speak with about energy-related decisions for this facility? ___________________________________ ASK TO BE CONNECTED WITH THIS INDIVIDUAL.

INTRO2B

May I please speak with ___(insert from Intro2A)___________________

(IF CONTACT COMES TO PHONE, ASK INTRO2_1)

(IF CONTACT NOT AVAILABLE, SCHEDULE CALLBACK)

INTRO3

We are speaking with selected businesses and organizations to learn about their current load management and rate preferences.

The information you provide will be kept in strictest confidence. If you agree to participate in the survey, [UTILITY] will provide energy use and load information for your facility to the evaluation contractor. This information and your survey responses will be shared with the study team (the Energy Commission and its contractors, and [UTILITY]) only in a form that does not allow the identification of any business, individual or facility.

This interview should take about 15 minutes. Is this a good time for you or is there a better time I can call you back?

1	Yes	SC1
2	No, schedule callback	Call back
88	Refused	T&T

If utility contact information requested, please use the following:

SCE: Edward Lovelace (626) 302-1697

PG&E: Susan McNicoll (415) 973-7404

SDG&E: Leslie Willoughby (858) 654-1262

-

- **SC1.** First, what is your job title? [DON'T READ]

-

1	Facilities Manager	SC2
2	Energy Manager	SC2
3	Other facilities management/maintenance po	SC2
4	Chief Financial Officer	SC2
5	Other financial/administrative position	SC2
6	Proprietor/Owner	SC2
7	President/CEO	SC2
SC1_8	Other (Specify)	SC2
88	Refused	SC2

RESP: Are you responsible for any other facilities in the SDG&E service territory other than the facility located at (address)(city)?

HOWMANY: How many facilities in the SDG&E service territory are you responsible for?

I'd like to remind you that unless otherwise stated, all questions pertain to the facility located at (address)(city).

-

-

DR AWARENESS AND FAMILIARITY

First I'd like to ask you about your awareness of and experience with demand response programs being offered to (IOU) customers. For the purposes of this interview, Demand Response refers to actions customers take to temporarily reduce electrical load during short periods in response to peak demand shortages or high power supply prices.

F1. How familiar would you say your organization is with the Demand Response concept? Would you say your organization is:

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3
Refused	88
Don't Know	99

F2. Now I would like to ask you how familiar your organization is with several specific demand response programs offered by utilities and energy agencies in California. I'll read a brief description of each program and then ask whether your organization is very familiar, somewhat familiar, or not at all familiar with each program.

F2a. [UTILITY'S] Critical Peak Pricing tariff. The Critical Peak Pricing (CPP) tariff offers lower rates to customers who agree to reduce electricity use during up to 12 critical peak periods per summer. Customers on the CPP tariff pay higher rates during these peak periods, but receive reduced energy rates at other times. How familiar is your organization with [UTILITY'S] *Critical Peak Pricing* (CPP) tariff?

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3
Refused	88
Don't Know	99

F2b. [UTILITY'S] Demand Bidding Program. The Demand Bidding Program is a no-risk program whereby participants earn bill credits for reducing their power usage when contacted. How familiar is your organization with [UTILITY'S] *Demand Bidding Program* (DBP)

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3

Refused	88
Don’t Know	99

[IF SDG&E=1 ASK IN1c, ELSE SKIP]

F2c. San Diego Gas & Electric’s Hourly Pricing Option. The Hourly Pricing Option (HPO) is a daily-adjusted hourly electric rate that provides potential cost savings for customers who can shift energy usage to lower-priced hours. How familiar is your organization with San Diego Gas & Electric’s *Hourly Pricing Option?*

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3
Refused	88
Don’t Know	99

F2d. The California Power Authority’s *Demand Reserves Partnership* (DRP) Program. Like the Demand Bidding Program, customers provide demand reductions when contacted and receive payments for reductions; however, this program is offered by the California Power Authority. How familiar is your organization with this California Power Authority program?

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3
Refused	88
Don’t Know	99

F3. There are also two supporting incentives associated with these demand response programs. How familiar is your organization with each of the following demand response support efforts?

F3a. [UTILITY’S] *Bill Protection Plan* for the Critical Peak Pricing rate

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3
Refused	88
Don’t Know	99

F3b. [UTILITY’S] *Technical Assistance Incentive* for the Critical Peak Pricing Rate and Demand Bidding Program

Very familiar	1`
Somewhat familiar	2
Not at all familiar	3
Refused	88
Don't Know	99

[IF FAMILIAR WITH AT LEAST ONE OF DBP, CPP, HPO CONTINUE (F2a, b, c = 1 OR 2), ELSE SKIP TO F6]

F4. How did you and your organization learn about [IOU's] new demand response programs??

1. Personal contact from utility
2. Direct mail
3. Workshops/conferences
4. Other end users/customers
5. Energy service provider
6. Trade or industry group
7. Equipment vendors/consultants, etc.
8. Other (specify)

F5. About when did you first learn about these new demand response programs? Would you say:

1. Within the Past Month
2. Within the Past 3 months
3. Within the Past 6 months
4. Within the Past 9 months (Summer of 2003)
5. Within the Past year
6. More than a year ago
7. Refused
8. Don't know

F6. Do you recall receiving any of the following types of information on [UTILITY'S] new demand response programs?

F6a. General discussion with your utility representative of demand response program features?

Yes	1
No	2
Refused	88
Don't Know	99

F6b. Specific analysis of financial impact of participating in the new demand response programs from your utility representative?

Yes	1

No	2
Refused	88
Don't Know	99

F6c. Brochures and Print Materials about Demand Response Programs?

Yes	1
No	2
Refused	88
Don't Know	99

F6d. Do you recall receiving any other type of information on SDG&E's Demand Response Programs?Yes 1

No	2
Refused	88
Don't Know	99

F6DOT What other type of information on SDG&E's Demand Response Programs did you receive? Record Verbatim.

[IF F6a, b, c, or d = 1, THEN GO TO F7 ELSE SKIP]

F7. How helpful was this information in determining whether the new demand response programs would be of interest to your organization?

Very Helpful	1
Somewhat Helpful	2
Not Very Helpful	3
Refused	88
Don't Know	99

F7a. And why is that?

<VERBATIM>

GENERAL CPP AND DBP PERCEPTION

PE1. How would you describe your organization's attitude toward tariffs such as the Critical Peak Pricing rate that offer lower overall prices to customers who agree to reduce their electric load during limited critical peak periods, but charge more for the power used during those critical peak periods? Would you say:

Very positive	1
Somewhat positive	2

Somewhat negative	3
Very negative	4
Refused	88
Don't Know	99

PE1a. And why is that?

<VERBATIM>

PE2. How would you describe your organization's overall attitude toward programs such as the Demand Bidding Program that pay an incentive to customers who reduce their usage during peak periods without imposing a penalty for failure to do so? Would you say?

Very positive	1
Somewhat positive	2
Somewhat negative	3
Very negative	4
Refused	88
Don't Know	99

PE2a. And why is that?

<VERBATIM>

CPP/DBP/HPO RATE PARTICIPATION DECISIONS

Next I'd like to ask you about your organizations decisions regarding these new demand response programs.

[IF CPP PART FLAG=1 OR CPP ELIGIBLE FLAG=0 OR F2a NE 1 OR 2, SKIP TO DM2]

DM1. Which of the following 5 statements best describes your organization's decision-making about whether to participate in the Critical Peak Pricing program for this location?

1. Have decided to participate in CPP
2. Have decided not to participate in CPP
3. Still deciding on whether to participate in CPP
4. Have not seriously evaluated whether to participate in CPP
5. Didn't think we were eligible
6. Refused
7. Don't know

[IF DBP PART FLAG=1 OR DBP ELIGIBLE FLAG=0 OR F2b NE 1 OR 2, SKIP TO DM2]

DM2. Which of the following 5 statements best describes your organization's decision-making about whether to participate in the Demand Bidding Program for this location?

1. Have decided to participate in DBP
2. Have decided not to participate in DBP
3. Still deciding on whether to participate in DBP

4. Have not seriously evaluated whether to participate in DBP
5. Didn't think we were eligible
6. Refused
7. Don't know

[IF SDG&E FLAG=1, IF HPO PART FLAG=1 OR HPO ELIGIBLE FLAG=0 OR F2c NE 1 OR 2, SKIP TO DM2]   [CONSIDER ROTATING HPO WITH CPP?]

DM3. Which of the following 5 statements best describes your organization's decision-making about whether to participate in the Hourly Pricing Program for this location?

1. Have decided to participate in HPO
2. Have decided not to participate in HPO
3. Still deciding on whether to participate in HPO
4. Have not seriously evaluated whether to participate in HPO
5. Didn't think we were eligible
6. Refused
7. Don't know

[SKIP FOR THOSE THAT MADE CPP, DBP, HPO DECISION (DM1=1 OR 2; OR DM2=1 OR 2; OR DM3=1 OR 2)]

DM4. With the information you have as of today, how likely would say your organization is to participate in one of these new demand response programs for this location?

1. Highly likely
2. Somewhat likely
3. Not sure
4. Somewhat unlikely
5. Very unlikely
6. Refused
7. Don't know

[IF DM4=1 OR 2]

DM4a. Which demand response program are you most likely to participate in, is it:

1. Critical Peak Pricing
2. Demand Bidding
3. Hourly Pricing
4. CPA Demand Reserves Program
5. Other, Specify____________________
6. Refused
7. Don't know

REASONS FOR PARTICIPATION

[ASK PA1 FOR ALL PARTS (CPP OR DBP OR HPO FLAG=1) AND LIKELY PARTICIPANTS (DM1=1, OR DM2=1, OR DM3=1 OR DM4=1 OR 2)]

PA1_1. What are the reasons /your organization decided to sign up for/organization is likely to sign up/ [CATI LOGIC FOR PHRASE] your for this demand response program for this location? [VERBATIM]

PA1_2 Can you think of another reason?

PA1_3 Can you think of another reason?

PA1_4 Can you think of another reason?

PA1_5 Can you think of another reason?

[IF MORE THAN ONE REASON, ASK PA1A]

PA1_A. And which of those reasons was most important? [VERBATIM]

PA2. How much demand reduction, as a percent of your normal summer afternoon peak demand, is your organization LIKELY to provide this summer during the limited demand response program periods from this location?

1. 0 percent
2. 1 to 5 percent
3. 6 to 10 percent
4. 11 to 20 percent
5. 20 to 50 percent
6. Over 50 percent
7. Refused
8. Don't know

REASONS FOR NON-PARTICIPATION

[ASK NP1 IF DECIDED NOT TO PARTICIPATE OR UNCERTAIN ABOUT, SOMEWHAT OR VERY UNLIKELY TO PARTICIPATE (DM1=2 OR DM2=2 OR DM3=2 OR DM4 = 3, 4 OR 5)]

NP1_1. What are the reasons why your organization is unlikely/uncertain/ [CATI LOGIC FOR PHRASE] to participate in these new demand response programs? [VERBATIM]

NP1_2 Can you think of another reason?

NP1_3 Can you think of another reason?

NP1_4 Can you think of another reason?

NP1_5 Can you think of another reason?

[IF MORE THAN ONE REASON, ASK NP2]

NP1A. And which of those reasons was most important? [VERBATIM]

BARRIERS TO PARTICIPATION

BA1-BA12. Now I'd like to describe some reasons organizations might not participate in demand response programs or would achieve only small demand reductions. On a 1 to 5 scale, where 1 indicates insignificant and 5 indicates extremely significant, please indicate how significant each of the following is as a concern about demand response program participation at this location. [ROTATE RANDOMLY]

B1. Effects on occupant comfort
B2. Effects on products or productivity
B3. Inability to adequately manage and monitor peak reductions
B4. Need for more information on how to achieve demand reductions
B5. Permit regulations that limit the running of backup generators
B6. Amount of potential bill savings
B7. Complexity of program rules
B8. Level of on-peak prices or non-performance penalties
B9. Inadequate program information
B10. Uncertainty over future changes in program price signals and rules
B11. Time and effort it takes to participate
B12. Inability to reduce peak loads

BA2OTC01-BA2OTC11. What other concerns, if any, does your organization have about trying to temporarily reduce summer peak loads at this location through participation in demand response programs?

<VERBATIM>

CURRENT ACTIVITY AND ASSOCIATED MOTIVATIONS

CDR1. Is this location currently on a time-of-use rate where the price you pay varies by time period within summer days?

Yes	1
No	2
Refused	88
Don't Know	99

[IF CDR1 = 1, ELSE SKIP TO CDR3]

CDR1a. Has your firm taken action in the past to SHIFT usage from higher priced to lower priced hours in response to these time-of-use price differences?

Yes	1
No	2
Refused	88
Don't Know	99

[IF CDR1a = 1, ELSE SKIP TO CDR3]

CDR2. What actions has your organization taken to shift usage from these higher priced to lower priced rate periods?

<VERBATIM>

CDRNU. Which of the following best describes WHEN your organization took the majority of these actions to shift usage from higher priced to lower priced rate periods? Would you say:

- Primarily before the California Energy Crisis [before Summer 2000] 1
- Primarily during or after the California Energy Crisis [after Summer 2000]....2
- Significant load shifting actions were taken both before and after the California Energy Crisis....3
- Refused 88
- Don't know 99

CDR3. Have you made any /other/ significant changes in the way your organization uses electricity at this site since the California energy crisis began in the summer of 2000?

Yes	1
No	2
Refused	88
Don't Know	99

CDR3a. And what were the principal changes made? [VERBATIM]

CDR4. By roughly how much do you think all of these load shifting and other changes have changed the summer on peak usage at this facility as compared to its summer on peak usage prior to the California energy crisis?

1	0 to 2 percent decrease	
2	3 to 5 percent decrease	
3	6 to 10 percent decrease	
4	10 to 15 percent decrease	
5	16 to 20 percent decrease	
6	More than 20 percent decrease	
7	0 to 2 percent increase	
8	3 to 5 percent increase	
9	6 to 10 percent increase	
10	10 to 15 percent increase	
11	16 to 20 percent increase	
12	More than 20 percent increase	
88	Refused	
99	Don’t know	

BILL SAVINGS REQUIRED FOR SINGLE POINT, GENERIC TYPE OF PARTICIPATION

Now I am going ask you a couple of questions about the amount by which your organization would be able to reduce it’s electricity demand in response to notification from [UTILITY] due to high utility system demand. Assume for these questions that the reductions at this location would be requested for only a few hours in the late afternoon on roughly four weekdays in the summer and that the days are not sequential.

SA1. What percentage of your annual electricity bill would you need to save as an incentive to reduce your demand at this location by 5% for a few hours on roughly four weekdays in the summer?

1. 0 percent
2. 1 to 5 percent
3. 6 to 10 percent
4. 11 to 20 percent
5. 20 to 50 percent
6. Over 50 percent
7. No amount would be adequate
8. Refused
9. Don’t know

SA2. And what percentage of your annual electricity bill would you need to save as an incentive to reduce your demand at this location by 15% for a few hours on roughly four weekdays in the summer?

1. 0 percent

2. 1 to 5 percent
3. 6 to 10 percent
4. 11 to 20 percent
5. 20 to 50 percent
6. Over 50 percent
7. No amount would be adequate
8. Refused
9. Don't know

DR CAPABILITY AND POTENTIAL ACTIONS

CA1. What percentage of your normal summer afternoon peak demand could you reduce for a few hours on roughly four weekdays in the summer, provided you were notified the day before and you were give sufficient financial motivation?

1. 0 percent
2. 1 to 5 percent
3. 6 to 10 percent
4. 11 to 20 percent
5. 20 to 50 percent
6. Over 50 percent
7. Refused
8. Don't know

CA2. If the motivation were sufficient, which of the following temporary demand reduction actions would you be willing to consider for a few hours on roughly four weekdays in the summer?

CA2a. Allow the temperature to rise in the occupied space (from 1 to 5 degrees)?

1	Yes	
2	No	
99	Don't know/refused	

CA2b. Shut off a portion of the air conditioning system, such as ventilation fans in areas with low occupancy (such as storage or warehouse space)?

1	Yes	
2	No	
99	Don't know/refused	

CA2c. Reduce overhead lighting (dim some lights, turn every other lamp off, turn off lights near windows?

1	Yes	
2	No	

99	Don’t know/refused	

CA2d. Reduce or shut off some or all production processes?

1	Yes	
2	No	
99	Don’t know/refused	

CA2e. Are there any other actions you might take (Please Specifiy).

Action #1		
Action #2		

CA3. And which, if any, of the following types of energy information, management, load monitoring, and control capabilities do you currently have for this location?

CA3a. The ability to view hourly demand on an in-house energy information system?

Yes	1
No	2
Refused	88
Don’t Know	99

CA3b. The ability to view your hourly demand on your utility’s website?

Yes	1
No	2
Refused	88
Don’t Know	99

CA3c. The ability to automatically control a significant portion of your electricity load through energy management or other control systems?

Yes	1
No	2
Refused	88
Don’t Know	99

DECISION PROCESSES AND GENERAL ENERGY MARKET PERCEPTIONS

- Now I'd like to ask some questions about how your organization makes decisions about participating in utility-offered demand response-programs or tariffs.

-
- EM1a. Which of the following best characterizes who has ultimate authority in your organization with respect to participation in a new utility rate or program such as demand response programs? Would you say that it is: [READ LIST]

- One individual at this facility 1
- One individual at parent organization 2
- A group of individuals at this facility 3
- A group of individuals at parent organization 4
- A group of individuals at both this facility and the parent organization 5
- [DON'T READ] Don't Know 98
- [DON'T READ] Refused 99

EM2. What is the typical time frame for your organization to make decisions about participating in demand response programs? Would you say:

- Less than 1 month 1
- 1 to 3 months 2
- More than 3 months 3
- Refused 88
- Don't know 99

-
- EM2a. And what are the primary factors that your organization considers when making decisions about utility rate offerings and demand response programs?
-
- <VERBATIM>
-
- Now I have a few questions about electricity markets and prices.

EM3. How closely does your organization monitor and analyze electricity markets and prices? Would you say,

Very closely 1

Somewhat closely 2

Not very closely	3
Refused	88
Don't Know	99

-

- EM4. And over the next three years, does your organization expect wholesale electricity prices to increase, decrease, or stay about the same?

-

1	Increase	
2	Decrease	
3	Stay about the same	
88	Refused	
99	Don't know	

EM5. In your organization's view, how likely is it that California's power supplies will be inadequate to meet expected power demand over the next three years? Would you say:

Very likely	1
Somewhat likely	2
Somewhat unlikely	3
Very unlikely 4	
Refused	88
Don't Know	99

EM6. On hot high demand summer days, how much do you expect the wholesale market price of electricity varies from lowest daytime price to highest?

1. 10% variation,
2. 50% variation,
3. 100% variation,
4. 200% variation,
5. 500% variation,
6. 1000% variation,
7. More than 1000% variation from lowest daytime price to highest
8. Refused
9. Don't Know

EM7. How concerned is your organization about energy costs relative to other costs of running your business?

Very concerned	1
Somewhat concerned 2	

Relatively unconcerned	3
Refused	88
Don’t Know	99

ENHANCED AUTOMATION MATERIALS

Now I would like to shift the focus and ask you a few questions about building automation and control systems.

EA1. Have you ever heard of the term “Enhanced Automation”?

1	Vendor	
1	Yes	
2	No	**➔GO TO EA3**
99	Don’t know/refused	**➔ GO TO EA3**

EA2. What does the term “Enhanced Automation” mean to you?

<VERBATIM>

As you may know, the California Energy Commission is conducting an education campaign, called “Enhanced Automation” to inform customers of building automation and controls upgrades available to save money on their electric bills. Enhanced automation technologies improve the efficiency, comfort and control of buildings. They can provide information on building systems, energy costs, and increase flexibility of building operations. Examples include adding a new energy information system, re-programming an existing energy management system, or expanding a network of sensors and control devices. The education packet comes in a black and blue folder, and includes case studies of success stories, a Business Case Guidebook and a Technical Options Guidebook.

EA3 Have you ever received or heard about materials from the California Energy Commission, such as a brochure or case studies, discussing Enhanced Automation and advanced building controls?

1	Yes	
2	No	**➔GO TO EA8**
99	Don’t know/refused	**➔GO TO EA8**

EA4. How did you hear of the Enhanced Automation campaign?

1	Vendor	
2	Utility Representative	
3	Colleague or Trade Association	
4	Browsing/Searching the Internet	
5	In the Mail	

6	Other→**(SPECIFY______)**	
99	Don't know/refused	

EA5. What, if any, information did you receive directly from the Enhanced Automation Program? <READ LIST IF NEEDED; CHECK ALL THAT APPLY>

1	Brochure(s)	
2	Case studies	
3	Business Case Guidebook	
4	Technical Options Guidebook	
5	Guidebooks (don't know which one)	
6	Technical Assistance	
7	Visited website	
8	No materials, just heard about it	**→GO TO EA8**
9	Other **(SPECIFY____)**	
99	Don't know/refused	

EA6. How valuable were the Enhanced Automation materials or services you received? Would you say they were…

1	Very valuable	
2	Somewhat valuable	
3	Not valuable	
99	Don't know/refused	

EA7. And why is that?

<VERBATIM>

EA8. In the past 2 years, have you considered any automation investments for your control systems to improve your ability to manage your energy use?

1	Yes	
2	No	**→GO TO EA17**
99	Don't know/refused	**→GO TO EA17**

EA9. What are the reasons you considered these improvements to your control systems? (DO NOT READ, CHECK ALL THAT APPLY)

1	Save on energy costs	
2	Upgrade old equipment	
3	Increase flexibility of controls systems	
4	Be able to respond to dynamic pricing	
5	To increase occupant comfort	
8	Other **(specify_____)**	
99	Don't know/refused	

EA10. Did you actually install any of these controls improvements for your business?

1	Yes	
2	No	**➔GO TO EA12**
99	Don't know/refused	**➔GO TO EA12**

EA11. Which of these controls improvements have you made in the past few years to help manage your energy use? Anything else?

<RECORD ALL MENTIONS>

EA12. What or controls improvements have you considered to help manage your energy use, but not pursued?

<RECORD ALL MENTIONS>

[IF HAVE NOT CONSIDERED ANYTHING, SKIP TO EA14]

EA13. Why have you not pursued those improvements?

<RECORD ALL MENTIONS>

EFFECT OF EA MATERIALS ON EE/DR ACTIVITY

IF EA3 = (2 or 99) then SKIP TO EA17
(skip if don't recall receiving EA materials)

EA14. Did the Enhanced Automation educational materials or services influence your decision to take any of the energy efficiency or demand response actions or controls improvements you mentioned?

1	Yes	
2	No	**➔GO TO EA17**
99	Don't know/refused	**➔GO TO EA17**

EA15. Please describe which action(s)?

< VERBATIM>

EA16. How have the EA materials influenced your plans? Anything else?

<RECORD ALL MENTIONS>

ENHANCED AUTOMATION INFORMATION

EA17. How relevant is information on building automation improvements and advanced building controls to your business as a way to manage your energy use? Would you say it is…

1	Very relevant	
2	Somewhat relevant	
3	Somewhat irrelevant	
4	Very irrelevant	
99	Don't know/refused	

EA18. What type of information on building automation improvements would be most helpful to you and your business as a way to manage your energy use? (What else?)

< VERBATIM>

EA19. What method of communication would be most likely to get your attention? (For example, if the Energy Commission wanted to inform you of technical assistance or incentives available, what would be the best way to pass that information to you?) DO NOT READ, CHECK ALL THAT APPLY.

1	Contact from a utility representative	
2	Contact from a vendor	
3	Utility bill insert	
4	Email from the Energy Commission	
5	Phone call from the Energy Commission	
6	Letter from the Energy Commission	
7	Information on the Commission website	
8	Other **(specify_____)**	
9	No method, don't pay attention to unsolicited information	
99	Don't know/refused	

EA20. Do you have any other suggestions for how the Energy Commission could best promote investments in automation improvements and advanced controls to customers, such as yourself?

<VERBATIM>

- DIFF You mentioned earlier that you are responsible for ______ other facilities in the SDG&E service territory. Overall, wouldyou say that the responses that you have provided for the facility located at (address) (city) are generally representative of all of your facilities that your are responsible for?

Yes 1

No 2

Refused 88

Don’t Know 99

DIFFHOW What things come to mind that would make this facility different than the other facilities you manage in the SDG&E service territory, relating to the questions we have discussed today? RECORD VERBATIM.

DIFFHOW2 Anything else?

DIFFHOW3 Anything else?

-

-

FIRMOGRAPHIC CHARACTERISTICS

- **Now I'd like to ask a few quick questions about this facility. Unless otherwise stated, all questions pertain to THIS FACILITY [RESTATE FACILITY LOCATION IF NECESSARY].**

-

- **EC1.** ....What is the main activity performed at this location?

-

1	Office	EC2
2	Retail (non-food)	EC2
3	College/university	EC2
4	School	EC2
5	Grocery store	EC2
6	Convenience store	EC2
7	Restaurant	EC2
8	Health care/hospital	EC2
9	Hotel or motel	EC2
10	Warehouse	EC2
11	Personal Service	EC2
12	Community Service/Church/Temple/Municipality	EC2
13	Industrial Electronic & Machinery	EC2
14	Industrial Mining, Metals, Stone, Glass, Concrete	EC2
15	Industrial Petroleum, Plastic, Rubber and Chemicals	EC2
16	Other Industrial	EC2
17	Agricultural	EC2
18	Transportation/Telecommunications/Utility	EC2
77	Other (SPECIFY)	EC2
88	Refused	EC2
99	Don't know	EC2

-

- **EC2.**Approximately how many square feet does **your organization occupy in this facility?**

-

1	Less than 10,000 square feet	EC3
2	10,000 but less than 20,000 square feet	EC3
3	20,000 but less than 50,000 square feet	EC3
4	50,000 but less than 100,000 square feet	EC3
5	100,000 but less than 200,000 square feet	EC3
6	200,000 but less than 300,000 square feet	EC3
7	300,000 but less than 400,000 square feet	EC3
8	400,000 but less than 500,000 square feet	EC3
9	Over 500,000 square feet	EC3
10	Ag/Non-facility – Outdoors	EC3
88	Refused	EC3
99	Don't know	EC3

-

- **EC3.**..Does your organization.....

1	Own this space	EC5
2	Lease this space	EC4
3	Own a portion and lease the remainder	EC4
88	Refused	EC5
99	Don't know	EC5

- **EC4** Does your organization pay its own electric bill directly to [UTILITY] or is electricity provided under your lease arrangement?

1	Pay own electric bill	EC5
2	Part of the lease arrangement	EC5
88	Refused	EC5
99	Don't know	EC5

- **EC5** What percent of your organization's total annual operating costs do energy costs represent?

1	Less than 1 percent	EC5A
2	1 to 4 percent	EC5A
3	5 to 10 percent	EC5A
4	11 to 25 percent	EC5A
5	Over 25	EC5A
88	Refused	EC5A
99	Don't know	EC5A

- EC5A Has your organization assigned responsibility for controlling energy usage and costs to any of the following?

1	An in-house staff person	EC6
2	A group of staff	EC6
3	An outside contractor	EC6
4	No one	EC6
88	Refused	EC6
99	Don't know	EC6

- **EC6.** Approximately how many locations does your organization have in California?

1	1	EC7
2	2 to 4	EC7
3	5 to 10	EC7
4	11 to 25	EC7
5	Over 25	EC7
88	Refused	EC7
99	Don't know	EC7

- **EC7.**What is the approximate number of full-time equivalent workers of all types employed by your organization at this facility?

-

1	1 to 10	
2	11 to 50	
3	51 to 100	
4	100 to 250	
5	251 to 500	
7	501 to 1000	
8	Or, over 1000	
88	[Don't read] Refused	
99	[Don't read] Don't know	

-

- **EC8.**What is the approximate daily operating schedule at this location during the summer for weekdays and weekends?

-

- **EC8a.** Weekdays

-

Start Cod	Start Time	End Code	End Time
1	1 am	1	1 am
2	2 am	2	2 am
3	3 am	3	3 am
4	4 am	4	4 am
5	5 am	5	5 am
6	6 am	6	6 am
7	7 am	7	7 am
…	…Code 8 am through 11 pm	…	…Code 8 am through 11
24	12 pm	24	12 pm
88	Refused	88	Refused
99	Don't know	99	Don't know

-

- **EC8b.** Weekends

-

Start Cod	Start Time	End Code	End Time
1	1 am	1	1 am
2	2 am	2	2 am
3	3 am	3	3 am
4	4 am	4	4 am
5	5 am	5	5 am
6	6 am	6	6 am
7	7 am	7	7 am
…	…Code 8 am through 11 pm	…	…Code 8 am through 11
24	12 pm	24	12 pm
88	Refused	88	Refused
99	Don't know	99	Don't know

-

- DAYS Are there any days of the week, Monday through Sunday that you are usually closed?
-

1	Sunday	EC5A
2	Monday	EC5A
3	Tuesday	EC5A
4	Wednesday	EC5A
5	Thursday	EC5A
6	Friday	
7	Saturday	
8	Open Every Day	
88	Refused	EC5A
99	Don't know	EC5A

-

- **EC9A.** Which of the following is the LARGEST a end uses in terms of electricity consumption for this facility?
-

EC9a	First Largest	EC9b	Second Largest
1	Lighting	1	Lighting
2	HVAC	2	HVAC
3	Continuous processing	3	Continuous processing
4	Batch processing	4	Batch processing
5	Refrigeration	5	Refrigeration
6	Other, Specify______________	6	Other, Specify_________
88	Refused	88	Refused
99	Don't know	99	Don't know

-
- **EC9B. And which would you say used the SECOND most electricity?**
-

EC9a	First Largest	EC9b	Second Largest
1	Lighting	1	Lighting
2	HVAC	2	HVAC
3	Continuous processing	3	Continuous processing
4	Batch processing	4	Batch processing
5	Refrigeration	5	Refrigeration
6	Other, Specify______________	6	Other, Specify_________
88	Refused	88	Refused
99	Don't know	99	Don't know

-
- EC10. Does this location have any on-site electricity generators?
-

1	Yes, for backup/standby purposes only	
2	Yes, as an everyday supplement or replacement for electric purchases from the grid	
3	No	
88	Refused	
99	Don't know/	

-

- [IF EC10 = 1 or 2, ELSE SKIP TO CL1]
-
- EC10a. What percent of this location's electricity load can be met by your on-site generation?

- ______ Percent (allow > 100%)

- EC10b. Are their legal restrictions on the number of hours your on-site system can run during the summer?

-

1	Yes	
2	No	
88	Refused	
99	Don't know/	

-

CLOSE

CL1. Do you have any final comments or suggestions about demand response programs being offered by (IOU)?

<VERBATIM>

END OF EXHIBIT D*

EXHIBIT H: RESIDENTIAL DLC DR POTENTIAL TELEPHONE SURVEY

Customer Name ____
Respondent ____
Address ____
City, State, Zip code ____
Phone # ____
Electric Account # ____
Survey date ____

Introduction

We are calling on behalf of Utility XYZ about a potential new energy management program that you could be eligible for. We would like to ask you a few questions about your residence, energy using equipment, and interest in this potential new energy program. This survey will take about 10-15 minutes to complete.

HOME AIR CONDITIONING SYSTEM INFORMATION (DELETE THIS SECTION IF AIR CONDITIONING EQUIPMENT IS NOT BEING CONSIDERED FOR INCLUSION IN THE PROGRAM.)

1. I'll start by asking about your home's air conditioning system. What type of air conditioning systems do you have in your home, if any? (Read list if needed.)
   a) Electric central AC (with cooling ducts to different rooms)
   b) Natural gas central AC (do not consider "freon" coolant as "gas")
   c) Electric heat pump
   d) Building cooling system that serves more than our residence or apartment
   e) Window or room air conditioners. How many? ________________
   f) Evaporative coolers
   g) Other (specify)____
   h) No AC system of any type (skip to #5)

2. About how old is your air conditioner?
   a) 1-2 years
   b) 3-5 years
   c) 6-10 years
   d) 11-20 years
   e) More than 20 years
   f) Don't know

3. How do you operate your air conditioner during working hours (8 am to 6 pm)?
   a) Set the thermostat to about ______ degrees
   b) Set the control switch to "on" and let it run
   c) Only run the AC on hot days. About how many days per month? _____
   d) Shut it off most of that time
   e) Other (specify) ____

4. How do you operate your air conditioner during evening and nighttime hours?
   a) Set the thermostat to about ______ degrees
   b) Set the control switch to "on" and let it run
   c) Only run the AC on hot days. About how many days per month? _____
   d) Shut it off most of that time
   e) Other (specify) ____

HOME HEATING SYSTEM INFORMATION (DELETE THIS SECTION IF HEATING EQUIPMENT IS NOT BEING CONSIDERED FOR INCLUSION IN THE PROGRAM.)

5. Next I want to ask about your home's main heating system. Does the main heating system serve only your residence or apartment or other residences/apartment as well? (The main heating system is the one that is used most often.)
   a) Heating system serves only this residence
   b) Heating system serves multiple residences
   c) No heating system serves the residence (skip to # 11)
   d) Don't know

e) Other (specify)____

6. What type of fuel does your heating system use? (Check all that apply)
   a) Electricity
   b) Natural gas (skip to #11)
   c) Propane (skip to #11)
   d) Oil (skip to #11)
   e) Solar energy (skip to #11)
   f) Don't know (skip to #11)
   g) Other (specify): ___________________________________(skip to #11)

7. Which of the following best describes your electric heating system?
   a) Central forced air furnace
   b) Central furnace with hot water heat distribution
   c) Boiler
   d) Heat pump
   e) Individual baseboard heaters located near the floor
   f) Individual wall heating units with fans
   g) Portable heaters
   h) Other (specify)____

8. About how old is your heating system?
   a) 1-2 years
   b) 3-5 years
   c) 6-10 years
   d) 11-20 years
   e) More than 20 years
   f) Don't know

9. How do you operate your heating system during working hours (8 am to 6 pm)?
   a) Set the thermostat to about ______ degrees
   b) Set the control switch to "on" and let it run
   c) Only run it on cold days. About how many days per month? _____
   d) Shut it off most of that time
   e) Other (specify) ____

10. How do you operate your heating system during evening and nighttime hours?
    a) Set the thermostat to about ______ degrees
    b) Set the control switch to "on" and let it run
    c) Only run it on cold days. About how many days per month? _____
    d) Shut it off most of that time
    e) Other (specify) ____

HOME HOT WATER HEATER INFORMATION (DELETE THIS SECTION IF HOT WATER HEATERS ARE NOT BEING CONSIDERED FOR INCLUSION IN THE PROGRAM.)

11. Next I want to ask about your home's hot water heater. Does your water heater serve only your residence or apartment or other residences/apartment as well?
    a) Hot water heater serves only this residence

b) Hot water heater serves multiple residences
c) No hot water heater serves the residence (skip to # 15)
d) Don't know

12. What type of fuel does your water heater use?
    a) Electricity
    b) Natural gas (skip to #15)
    c) Propane (skip to #15)
    d) Oil (skip to #15)
    e) Solar energy (skip to #15)
    f) Don't know (skip to #15)
    g) Other (specify): ___________________________________(skip to #15)

13. Is your hot water heater a regular stand-alone tank/system, or another type of system?
    a) Stand-alone tank/system (standard residential water heater)
    b) Tankless "instantaneous" hot water heater
    c) Heating system furnace also heats hot water
    d) Other (specify)____

14. About how old is your water heater?
    a) 1-2 years
    b) 3-5 years
    c) 6-10 years
    d) 11-20 years
    e) More than 20 years
    f) Don't know

HOME SWIMMING POOL INFORMATION (DELETE THIS SECTION IF POOL PUMPS OR POOL HEATING EQUIPMENT IS NOT BEING CONSIDERED FOR INCLUSION IN THE PROGRAM.)

15. Does your home have a swimming pool?
    a) Yes, private pool
    b) Yes, pool for apartment complex
    c) No (skip to # 19)

16. Is the swimming pool heated?
    a) Yes
    b) No (skip to #18)

17. What type of fuel does the swimming pool heater use?
    a) Electricity
    b) Natural gas
    c) Propane
    d) Oil
    e) Don't know
    f) Other (specify): ___________________________________

18. Does your swimming pool have a pump that circulates the water?
    a) Yes

b) No

INTEREST IN DIRECT LOAD CONTROL PROGRAM (SKIP IF NO OWNERSHIP OF MAJOR ELECTRICAL EQUIPMENT PREVIOUSLY ASKED ABOUT)

19. Utility XYZ is considering starting an energy management program for customers like yourself that would include a rate discount or free programmable thermostat (depending on the utility's plans). To qualify for this program, you would agree to allow the utility to cycle your AC, water heater or other major electrical equipment on very hot/cold "peak demand" days. This cycling would not harm your electrical equipment or cause much of a change in the temperature of your home. Would you be interested in participating in such a program?
    a) Definitely yes
    b) Depends of the amount/type of incentive offered
    c) Definitely no
    d) Other response: ____
    e) Don't know

20. Would receiving a free programmable thermostat that's installed for you be sufficient incentive to sign up for such a program?
    a) Yes (skip to #22)
    b) No
    c) Don't know
21. About how much of an annual rate discount would you require to sign up for such a program? Would you require a …
    a) $30 or less annual discount
    b) $31- $60 annual discount
    c) More than $60 annual discount
    d) Don't know

HOME AND HOUSEHOLD INFORMATION (DELETE QUESTIONS IN THIS SECTION THAT WON'T BE NEEDED FOR PROGRAM MARKETING OR IMPACT ESTIMATION PURPOSES.)

22. Which of the following housing types best describes your home?
    a) Single family detached home
    b) Single family attached house (duplex, townhouse, row house)
    c) Apartment building with 2-4 units
    d) Apartment building with 5 or more units
    e) Mobile home, house trailer
    f) Other (specify) ____

23. Do you or members of your household own this home or do you rent it?
    a) Own or buying
    b) Rent or lease
    c) Other (specify) ____

24. Is this residence usually occupied year-round, or only part of the year?
    a) Occupied year-round
    b) Occupied just during the ________________ season
    c) Occupied just on weekends or for vacations
    d) Don't know

25. About how large is this residence?
    a) Less than 1,000 square feet
    b) 1,000-1,999 square feet
    c) 2,000-2,999 square feet
    d) 3,000-3,999 square feet
    e) 4,000 square feet or more
    f) Don't know

26. About what year was this home constructed?
    a) 1949 or earlier
    b) 1950-1959
    c) 1960-1969
    d) 1970-1979
    e) 1980-1989
    f) 1990-1999
    g) 2000 or more recently
    h) Don't know

27. How many people live in the house on a full-time basis?
    a) _____ Number of adults18 years old or older
    b) _____ Number of children less than 18 years old
28. How old is the head of household?
    a) Less than 25 years old
    b) 25-34 years old
    c) 35-44 years old
    d) 45-54 years old
    e) 55-64 years old
    f) 65-74 years old
    g) 75 years old or older

29. What's the highest level of education completed by the head of household?
    a) No high school
    b) Some high school
    c) High school graduate
    d) Some college or associate degree
    e) Bachelor's degree
    f) Graduate study or degree
    g) Don't know

30. What's the employment status of the head of household?
    a) Employed fulltime
    b) Employed part time
    c) Self-employed
    d) Not employed or retired

e) Don’t know

31. What category best describes the total combined income for all household members from all sources in the past 12 months (not considering taxes)?
    a) Less than $20,000
    b) $20,000-29,999
    c) $30,000-39,999
    d) $40,000-49,999
    e) $50,000-74,999
    f) $75,000-99,999
    g) $100,000-149,999
    h) $150,000 or more
    i) Don’t know

End of Exhibit H

QUANTITATIVE STUDIES

Exhibit C: Working Group 2 Demand Response Program EVALUATION NONPARTICIPANT MARKET SURVEY REPORT EXECUTIVE SUMMARY (FINAL)

Working Group 2

Prepared for
Measurement and Evaluation Committee

Prepared by
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In Association with
Summit Blue LLC.

P1996

17.1. EXECUTIVE SUMMARY

This report is the second report of the Working Group 2 (WG2) Demand Response (DR) evaluation. In this second report, we present results from a quantitative survey of the eligible market of non-participants for the WG2 DR programs that was conducted in March 2004. The goal of the evaluation is to provide feedback to program managers and policy makers to help improve programs in the short-term for PY2004 and PY2005 and in the long-term to meet the DR goals established under ruling R.02-06-001 for PY2007. The first WG2 evaluation report, entitled *Summary of Phase 1 Research,* was distributed on April 8, 2004. The complete WG2 DR program evaluation scope includes process, market, and impact evaluation activities, as well as a sub-metering task. An interim process and impact evaluation report is currently in progress and is targeted for completion in late August as its own volume. The final project report will be completed after the summer 2004 programs have ended and all of the relevant data has been collected and analyzed.

17.1 1.1 SCOPE OF THIS REPORT

One of the key objectives of the WG2 Demand Response Evaluation is to carry out an end-user market assessment that focuses on demand response familiarity, receptivity, barriers, opportunities, and potential. Current participants in WG2 DR programs represent a fairly small portion of the potential market for these programs. These customers are being studied through a variety of evaluation tasks focused on program participants. To complement this participant research, several data collection and research activities have been designed to focus on non-participants, which comprise the vast majority of the market. In the Phase I evaluation effort, in-depth interviews were conducted with a small sample of non-participants.

As part of the Phase II evaluation, the evaluation team conducted a quantitative survey of non-participants. A telephone survey was conducted with a total of 500 non-participant customers among the PG&E, SCE, SDG&E (IOU) service territories. This survey seeks to improve our understanding of large non-residential customers (the greater than 200 kW market for PG&E and SCE, greater than 100kW for SDG&E) that were not participating in the Demand Bidding Program (DBP), Critical Peak Pricing (CPP), or SDG&E-only Hourly Pricing Option (HPO) as of March 2004. Note that the population of eligible customers for this survey does not include direct access (DA) customers, as these customers were ineligible for the DBP, CPP, and HPO [2]programs at the time of this research.

17.2 1.2 overview of key findings

The market survey of non-participants in the DBP and CPP programs provides a wealth of information that can be used to better understand both barriers and opportunities for demand response. When reviewing and interpreting the survey results, it is important to consider that the market for the current DR programs is still in an early, developmental stage, and that customers' responses to the questions asked are influenced by a wide variety of factors including their experience with the recent California electricity crisis, their experience with other related programs (e.g., interruptible programs), and their previous exposure to time-of-use rates. The results of the survey have both positive and negative implications with respect to the near-term prospects for increasing participation in the current DBP and CPP programs. Because this survey is one part of an overarching evaluation effort, and because the programs are still relatively new and evolving, we believe these results should be used to better understand the potential market for DR and develop ways of improving program offerings and customer support, rather than being used to pre-maturely assess whether the programs are destined to succeed or fail relative to current overall DR load reduction goals. With that

[2] CPP and HPO are technically tariffs but are commonly referred to as programs throughout the R.03-06-032 proceeding.

perspective in mind, highlights and implications of our key findings are discussed below. The full report and appendices provide details on survey methodology and detailed survey results.

17.2.1 DR Potential

Several questions were asked of customers to develop inputs for estimation of the potential load reduction associated with the large nonresidential market for demand response in the service territories of the three IOUs. It is important to note that the resulting estimates of potential are based on customer self-reports and have not been independently confirmed with on-site engineering analyses. **The average *technical* potential reported from the market was 16 percent**, however, the average varied widely by market segment. Based on rough initial estimates of the range of coincident peak demand for this population, the total **MW reduction potential** is likely **in the range of 1,200 to 1,800 MW**. Note, however, that this estimate of potential contains partial overlap with the IOUs' current interruptible participants. The size of the DR potential drops when customers are asked to report how much they would require in bill savings to deliver DR load reductions. **At bill savings similar to those associated with the current DBP and CPP programs** (less than three percent of annual bills), the **potential decreases by almost an order of magnitude, to 100 to 200 MW**. At the same time, somewhat surprisingly, the vast majority of the market says they are willing to consider taking specific DR actions on a limited number of hot summer afternoons. Also of note is the fact that significant DR potential was reported across all eligible size groups, including the smallest customers.

17.2.2 Familiarity with DR Programs

Overall, familiarity with the demand response *concept* was quite high with 92 percent of the market[3] indicating some level of familiarity and half reporting they were "very familiar". **Levels of familiarity reported for the DBP and CPP programs were reasonably high** and similar (64 percent versus 61 percent of the market, respectively). **Familiarity with the CPA-DRP program was significantly lower**, with only one-third of the market reporting some level of familiarity. The main source of information about these programs came from personal contact with their utility.

17.2.3 DR Barriers

Customers indicated that there are numerous barriers that limit their ability and willingness to participate in DR programs. In rating potential barriers to participation and implementation, **the number one concern** for the market as a whole **was "Effects on Products or Productivity"**. **The next largest concerns were "Amount of Potential Bill Savings", "Level of On-peak Prices or Non-performance Penalties", and "Inability to Reduce Peak Loads".** The least significant concern reported was "Inadequate program information". The rating of barrier importance varied greatly by market segment, for example, Institutional and Office customers ranked concerns over occupant comfort very high, while industrial customers considered this a relatively insignificant issue. **Barriers that were more of a concern for those** who said they were ***very likely* to participate** in DBP or CPP **included** "Amount of Potential Bill Savings", **"Complexity of Program Rules", "Uncertainty over Future Program Changes",** and "Level of On-Peak Prices or Non-Performance Penalties" all of which indicate concerns with program design, economics and change associated with a developing market rather than actual load reduction.

[3] "Market" here refers to the energy-weighted customer survey results. See Appendix C for weighting details. Un-weighted and Premise weighted results are presented in Appendix D.

17.2.4 Likelihood of Participating in DBP/CPP

Somewhat surprisingly, 19 percent of the market indicated some likelihood that they would participate in one of the programs and **10 percent said they were "highly" likely**. The percentage of customers reporting they are going to participate in either the DBP or CPP program is much larger than the number of customers that have signed up for the programs since the survey. One would expect self-reports of participation intent would over-report actual participation, however, the gap between self-reported likelihood to participate and current participation is much larger than one would expect. If these self-designated "likely" participants do not end up signing up for the programs, it would be useful to assess their reasons for not doing so later in this evaluation.

Likely participants reported the main reason they may participate was to lower their energy bills (54 percent). **Other significant reasons** reported for considering participation were because there were **no risks or penalties associated with program participation** and because they believed it would **help mitigate power outages**. It is important to note that customers mainly participating to avoid outages may be less likely to enter a DBP bid based solely on high market prices unless it seems a blackout is looming. A fairly sizable portion of the market (13 percent) indicated they were likely to participate since doing so fit easily within their normal business operations. **Customers who indicated they were unlikely to participate** in any of the new DR programs **said the main reason was their inability to shed load** (53 percent). Financial reasons, conflicts with other program participation, lack of information and concerns over comfort were also reported as reasons for low likelihood to participation.

17.2.5 Effects of Existing TOU Rates and CA Energy Crisis

Roughly half of the market on existing TOU rates reported they had already shifted their usage from higher priced to lower priced hours. The main action taken to reduce on-peak usage was to reschedule staff or equipment to off-peak periods. These actions were reportedly taken in significant numbers both before and after the recent California energy crisis. Fifty-seven percent of the market reported they have made other significant changes in electricity usage since the crisis. The average self-reported peak load reduction from these actions was nearly 10 percent.

17.2.6 General Electricity Market and Cost Perceptions

Customers were asked several questions aimed at assessing their level of attention to and assessment of electricity market trends. **Only a quarter of the market said that their organization analyzed electricity markets and prices very closely** and 32 percent reported following these markets somewhat closely. **The majority** of the market **believes** that **it is unlikely** that California's **power supply will be adequate to meet the expected power demand** over the next three years. A third of the market reported having no idea how much the wholesale market price of electricity varies from the lowest daytime price to the highest on high demand days. The rest of the population was evenly distributed between expecting the price to increase by 10 percent, 50 percent and more than 100 percent. **Nearly three-quarters** of the market stated their organization **is very concerned about energy costs relative to other costs of** running their business. **Roughly half of the market expects electricity prices to increase** over the next three years, a quarter expect them to stay the same and the remainder expect them to decrease.

17.2.7 Enhanced/Building Automation

Because building automation and energy information systems can help to facilitate demand response, customers were asked several questions about the relevance and use of such systems currently**.** **Three-quarters** of the market **indicated** that information about **building automation and controls was relevant to their business**. **One-third** of the market **said they had installed automation investments to manage their energy use** within the past two years. The level of building automation reported was moderate with 59 percent of the market reporting being able to view hourly demand on their utility's website, 54 percent stating they could automatically control a portion of their energy load on an in-house energy management system, and 41 percent able to view hourly demand on an in-house energy information system. Industrial customers reported having increased access to usage information, but less control capability, and institutional and commercial customers reported having increased control capability, but limited usage information.

17.3 1.3 Implications of survey Findings

The results of this market research effort point to both opportunities and challenges associated with achieving significant levels of participation in the DBP, CPP, or similar voluntary, price-responsive programs. On the one hand, almost twenty percent of the market reported they are somewhat or very likely to participate in the DBP or CPP (as of March 2004, the time of our survey); yet since then, actual participation increases have been significantly less than what these self projections would suggest. This could be due to a number of factors, for example, as suggested by our Phase I research: customers may not believe the level of financial compensation for program participation is acceptable; they may believe it is too difficult to get final internal approval to participate; they may believe participation itself is too complicated or entails significant hassle costs; or they may believe that there is no immediate need for them to participate because power supplies are adequate in the short term. In the case of the CPP, there are additional complexities. For example, customers may not fully understand or trust that they can save money without significant changes in their load profiles (this barrier may have been adequately addressed in recent changes to the Bill Protection plan).

Despite limited increases in participation in the DBP and CPP since this survey was conducted, our survey results indicate that there is a significant pool of DR potential available as well as a broad willingness to take specific DR actions on a limited basis. What is still somewhat unclear is the extent to which financial versus civic duty or reliability-related motivations are the key to tapping this potential and, concomitantly, how to convert these DR motivations into reliable DR resources.

Specific actions that should be considered in response to the findings from this survey and the Phase I research are presented below:

- Consider increasing the financial benefits of program participation (though only if cost-effectiveness can be maintained) or making it even easier for customers to participate in programs (e.g., lower customers' decision making and hassle costs).

- Aggressively market the recent changes in the Bill Protection Plan for the CPP to ensure customers understand that they can try the tariff with no initial risk.

- Consider reducing the 100 kW DBP bid minimum or otherwise facilitating the participation of chains or other aggregation groups.

- Take steps to actively mitigate the top customer-perceived market barriers to program participation – for example:
  - "Effects on Products or Productivity" – Continue utilizing existing and develop additional segment-specific case studies that demonstrate successful customer experiences with DR actions and provide strategies for minimizing or eliminating negative effects.
  - "Inability to Reduce Peak Loads" – Develop and test new approaches to providing high-value, customer-specific technical assistance to identify load reduction opportunities and strategies for implementation.[4] Investigate leveraging of energy efficiency program investments in audits and control systems to provide DR benefits at low marginal cost.
  - "Level of On-peak Prices or Non-performance Penalties" – Continue and re-iterate customer communication messages that emphasize the no risk/low risk attributes of the DBP and CPP.
  - "Amount of Potential Bill Savings" – Emphasize significance of bill savings as fractions of monthly or summer bills in addition to annual bills.
  - "Uncertainty over Future Program Changes" – Continue regulatory, utility, and working group efforts to develop and maintain consistency in all peak load reduction programs, including reliability programs, while still making improvements where necessary (possibly by guaranteeing minimum program features for set periods of time).

- Continue utilizing and consider expanding technical support materials and related tools (e.g., Enhanced Automation Guidebooks, DR action cut-sheets, cases studies, on-line software, etc.).

Readers should note that the presence of a suggestion in the list above does not mean that the utilities or other parties are not already pursuing or proposing similar or closely related actions (e.g., recently proposed utility programs such as E-Sav, chain account aggregation, and a customer awareness and education campaign, as well as ASW's program proposal and Infotility's discussion of DR on-line tools.

End of Exhibit C

[4] The current Technical Assistance Incentives are going unspent. At the same time, there is evidence from the evaluation team's interaction with program participants that a number of them are clearly in need of advice on how best to achieve DR reductions in their facilities. We suggest that new approaches be piloted quickly (during the remainder of this summer, if possible) so that evidence for which approaches are most effective can be developed for future program years.

18. August 5, 2004

<u>EXHIBIT E</u>: CALIFORNIA RTP SUMMARY

Steven Braithwait and David Armstrong
Christensen Associates

January 14, 2004

19. SUMMARY

The California energy crisis of 2000/2001 is widely acknowledged to have been exacerbated by the missing link between wholesale power costs and retail electricity prices. Nearly all customers faced fixed retail prices and thus had no incentive to reduce load during capacity-constrained periods in which wholesale costs spiked to high levels, despite the fact that the load reductions would have helped relieve the capacity constraint. In March 2001, the California Assembly (in AB29X) authorized funding to install advanced automatic meter reading devices for all customer accounts with peak demands greater than 200kW in the state. The original intent of the installations was to support the development of RTP rate designs to encourage demand response, particularly load reductions during periods of low reserves and high wholesale electricity costs. However, to date no extensive RTP program has been approved. One of the barriers to potential implementation of RTP has been a lack of solid information on the likely effect of different forms of real-time pricing.

This report contains an analysis of the potential demand response effects of RTP in California. A key source of data used in the analysis comes from the experience of Georgia Power Company's successful RTP program, which serves some 1,600 of its large C & I customers. Specifically, available information on the degree of price responsiveness of RTP customers in various two-digit SIC code business categories was applied to data on similar groups of customers in California. The results were re-weighted to reflect the relative importance of those business types in California. The demand response impacts were calculated using software developed previously for the CEC, after calibration to total energy consumption data by 2-digit SIC groups for California.

Scaling results to the total commercial and industrial load in the state suggests a total baseline load of price-responsive RTP customers of approximately 5,000 MW. Demand response results for a traditional two-part RTP rate structure in which hourly prices exactly reflect wholesale costs suggest aggregate load reductions of 800 MW in the relatively few hours of highest RTP prices. If the market acceptance of RTP were scaled back, the resulting load reductions would be scaled accordingly (*e.g.*, at 50% market acceptance, load response would be 400 MW). Under an alternative case in which prices are unbundled and RTP prices include standard tariff T&D charges as well as wholesale energy costs, the expected load reduction at high prices falls to less than 700 MW.

RTP customers' total annual bill-saving benefits derived from their demand response in the case of GPC-style two-part RTP are estimated to be $10.3 million. In the case of an unbundled RTP rate structure that includes T&D charges, customer bill savings are $3 million. Utility wholesale cost savings in the high-cost scenario are $10.3 million in case in which RTP prices reflect wholesale costs, and $9.3 million in the RTP plus T&D case.

End of Exhibit E

EXHIBIT F: QUANTEC DRPRO™ SUMMARY

Estimating Demand-Response Potentials Using Quantec, LLC's DRPro™

Quantec, LLC is an energy and environmental consultancy headquartered in Portland, Oregon. The firm specializes in strategic planning and analytic services for the electric, gas and water utilities. Quantec's expertise in the area of demand-response includes strategy development, technical and market assessments, implementation support, and evaluation. Quantec has recently completed assignments in demand-response assessment for PacifiCorp, Bonneville Power Administration, Portland General Electric, Puget Sound Energy, Mid-American, and Aquila.

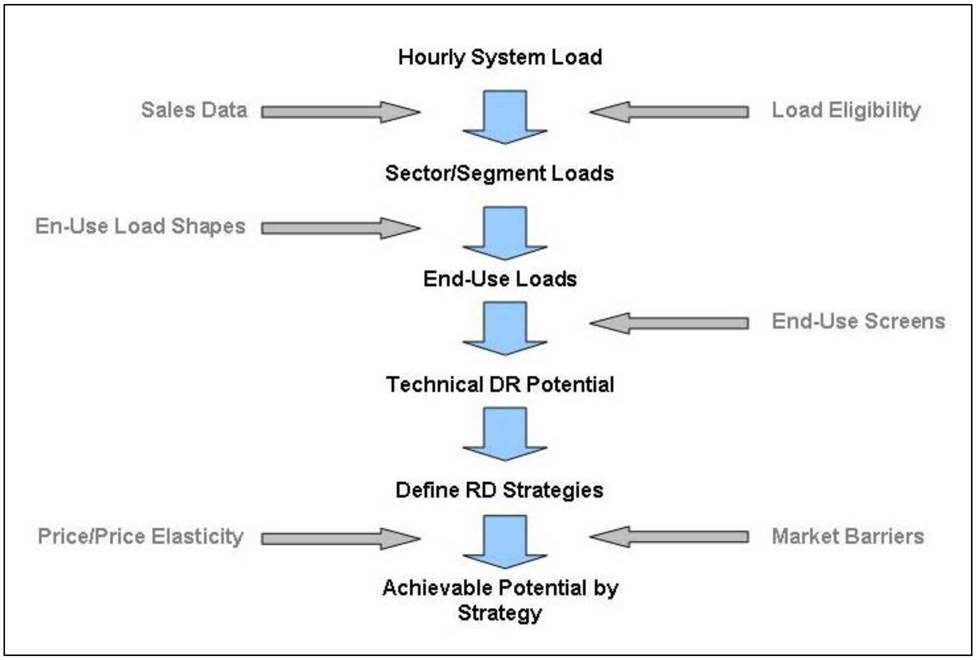
Assessment of demand-response potentials is supported by Quantec's DRPro™, a Microsoft Excel-based model specifically designed for estimating the technical and achievable potentials. ***Technical Potential*** is estimated at a gross level, assuming that all customer load sectors are potentially available for curtailment, except for those which clearly do not lend themselves to interruption. ***Achievable Potential*** is a subset of technical potential and represents that portion of technical potential that is available for curtailment subject to program participation rates and event participation rates. Both program and event participation rate are assumed to be functions of price. The magnitude of achievable potential, therefore, is a function of both market conditions and economic factors of price and price elasticity of response.

Specific demand-response strategies considered fall into two general classes of options depending on the reliability of the committed loads: ***Firm Options*** (Direct Load Control, Curtailment Contracts, and Dispatchable Stand-By Generation) and ***Non-Firm Options*** (Time-Varying Prices and Voluntary Demand Buy-Back).

Since demand-response options are not equally applicable to or effective in all segments of the electricity consumer market and their impacts tend to be end-use specific, DRPro™ employs a "bottom-up" approach, which involved breaking down system load by sector, market segment, and end use; estimating demand response potentials at the end-use level; and then aggregating the end-use demand-response potentials estimates to the sector level.

As shown in the diagram below, DRPro™ uses a seven-step process in calculating technical and achievable potentials.

(a) DRPro™ Methodology for Estimation of Demand Response Potential



19.2

19.3

1: Define Customer Sectors and Market Segments: System loads are System loads are disaggregated into five sectors: 1) residential 2) commercial, 3) industrial, 4) utilities and transportation, and 5) agricultural. The industrial sector and commercial sectors are further broken down into relevant market segments.

2- Adjust Customer Sector and Market Segment Loads by Load Eligibility Thresholds.

3: Create Sector and Segment Load Profiles: Using the utility's annual hourly interval data, total sales are broken down by sector and segment.

4: Develop Seasonal Sector- and Segment-Specific Typical Peak Day Load Profiles.

5: Estimate End-Use Shares by Sector and Market Segments: End-use shares are derived by applying annual end-use load profiles provided by the utility or obtained from Quantec's load shape library.

6: Estimate End-Use Technical Potential: For each demand response strategy (except dispatchable standby generation), technical potential is estimated at the end-use level as the fraction of appropriate end-use loads, which may be curtailed or interrupted in terms of both mean hourly loads during seasonal peaks and critical peak period. "Critical Peak" is generally defined as loads corresponding with the top one percentile (87 hours) of the system load duration curve. Total technical potential estimates for each sector and market segment are then derived as the sum of end-use-specific potentials.

7: Estimate Achievable Potential: Achievable potential is derived by adjusting technical potential by expected program participation and event participation rates. Both program and event participation rates are derived as logistic functions of price. For each demand-response strategy, the parameters of the logistic function are derived using empirical market data available from the experience of similar demand-response options.

Data requirements of DRPro™ fall into three general categories: 1) Demand-Response Program Data (options and strategies, applicable customer class, eligibility requirements), 2) Utility Data: (hourly system load profile, customer class load shapes, sales by customer class, and end-use load profiles, customer count by class and load size, costing periods), and 3) Market Data (market or avoided utility capacity and energy costs, expected program and event participation rates).

End of Exhibit F

EXHIBIT G: XENERGY DEMAND RESPONSE ASSESSMENT METHODOLOGY SUMMARY

20. DEMAND RESPONSE ASSESSMENT METHODOLOGY

20.1 Overview of Forecasting Methods

The crux of any DSM forecasting process involves carrying out a number of systematic analytical steps that are necessary to produce accurate estimates of demand response effects on system load. To conduct this analysis we developed a model to forecast demand reduction from demand response (DR) programs. We modified this model slightly to address Time Of Use (TOU) programs, and have discussed each approach separately below.

The supply curve method used to forecast DR impact is a simpler process than the measure-based models used to forecast energy efficiency. Information on the characteristics and penetration of potential DR measures did not exist in sufficient fashion to justify a measure-based modeling approach. We therefore relied on the professional judgment of a panel of experts to reach a consensus on key inputs to the supply curve models based on their experience in designing, managing, and evaluating DR programs.

The Delphi Approach

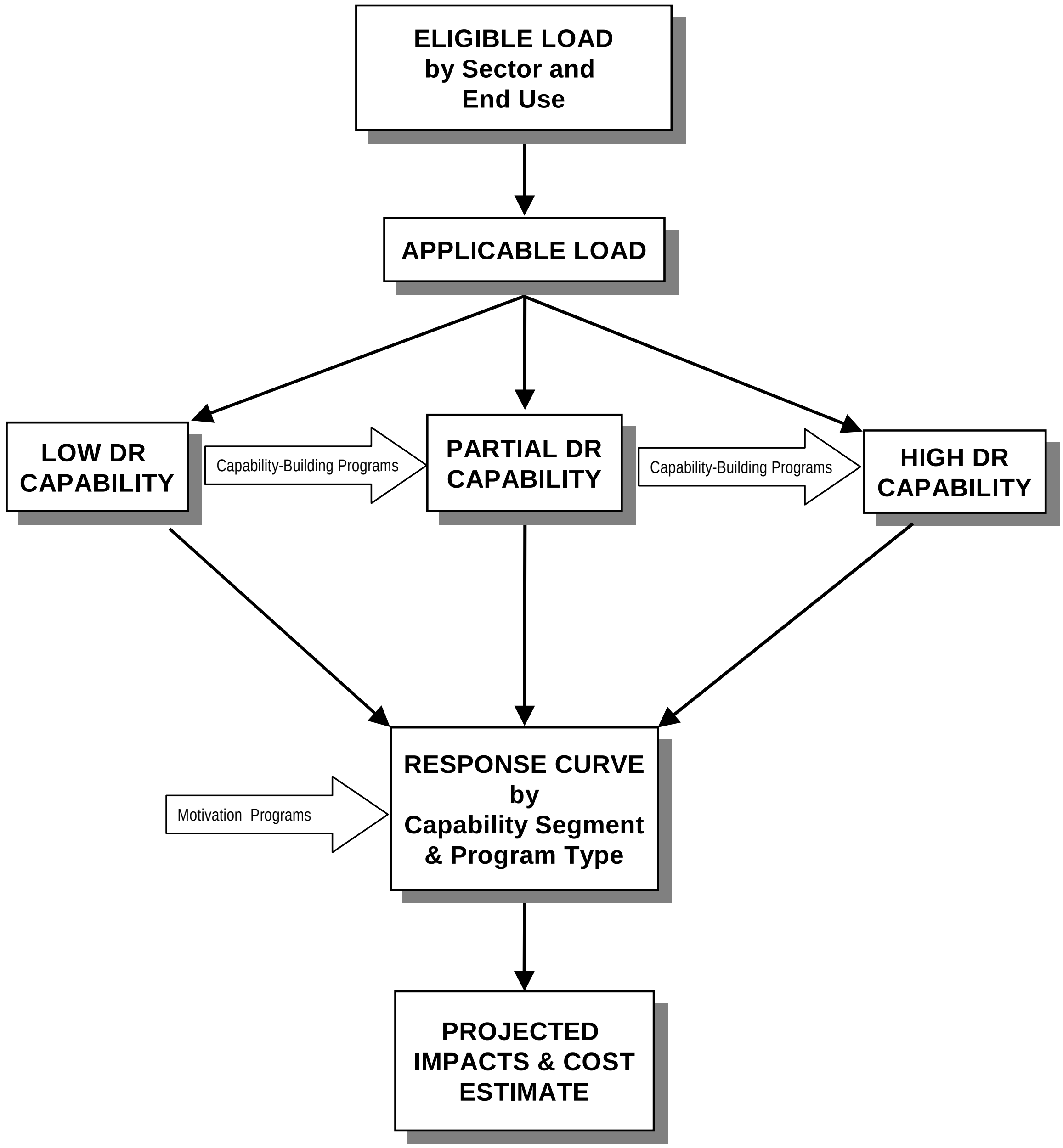
Relying on a panel of experts to develop the key inputs of a forecasting model is known as a Delphi estimation process. The power of this process comes from forcing the experts to reach a consensus. Although the opinion of any one expert is potentially biased, the Delphi process tends to reduce the effect of this bias by causing experts to convince their colleagues of their perspectives. Our expert team included the following.

- David Reed, Manager Product/Project, Pricing and Tariff, SCE
- Richard Barnes, Senior Vice President of Demand-Side Services, KEMA-XENERGY
- Fred Coito, Senior Consultant, KEMA-XENERGY
- Miriam Goldberg, Vice President of Planning and Evaluation, KEMA-XENERGY
- Bernie Neenan, Principal, Neenan Associates
- Frank Schultz, Principal Consultant, Far West Services
- Charles Goldman, Principal Investigator of Electricity Markets and Policy Group, Lawrence Berkeley National Lab (LBNL)
- Michael Rufo, Senior Vice President, Quantum Consulting

20.1.1 Overview of Demand Response Method

The forecast of demand reduction from potential demand response programs was produced using a series of DR supply curves that varied by program type and market segment. An overview of the DR modeling framework used is shown in Figure 2-1.

Figure 20-1
DR Forecasting Model Framework



20.1.2 Overview of Time of Use Method

In addition to the various demand response concepts, SCE was also interested in assessing the potential impacts of a voluntary Time-of-use (TOU) rate program directed at residential and non-residential customers that are not on a mandatory TOU rate schedule. Although an optional TOU rate has been available to most of these customers, it is not a concept that has been promoted by SCE, and thus there is a very low market penetration and awareness of TOU rates.

A Bass Diffusion Curve, along with electricity usage data by market segment and time periods, was used to forecast the amount of load that would voluntarily sign up for a TOU rate over time. The Bass Curve is commonly used to forecast the market acceptance of new concepts or existing concepts with very low market awareness.

The Bass curve produces forecasts of market penetration for a given point in time based on three parameters and on the total market penetration that had occurred before the time period being forecasted. The specific functional form of the bass curve is provided later in this section. The bass curve takes into consideration that only a portion of the market will eventually accept the concept, that a certain portion of the market are innovators, and that "word of mouth" recommendations from previous adopters have an influence on the amount of penetration that will occur in the future.

The Bass Curve was applied to seven market segments of electric accounts (5 residential and 2 non-residential). The five residential segments were based on average annual electric usage and dwelling type. The two non-residential segments were based on rate schedule, which is a function of maximum electric demand. Information on the number of accounts in each segment and on the average electric demand during the "peak" summer period[5] was provided by SCE based primarily on class load research data. The three parameters of the Bass curved were estimated by the expert panel and varied somewhat by segment. The experts also took into consideration the market acceptance of PG&E customers during the late 1980s and early 1990s where about 15,000 accounts per year voluntarily switch to a TOU rate as a result of comprehensive marketing by PG&E.

The Bass model resulted in an estimate of the number of accounts and thus the amount of load that would choose to be on a TOU rate each year. The final step to forecast the load impacts from a TOU rate was to estimate the load shifting that would occur from TOU pricing. The expert panel recognized that the amount of load shifting was highly dependent on the peak to off-peak price ratios. The assumption was made that the ratio of the peak to off-peak price would likely be about 3 to 1 and that this could result in the shifting of about 10%-15% of the peak period load to the off-peak period. It was felt by the panel that residential customers would be able to shift a higher percentage of peak load than non-residential customers. It was assumed that there would be no significant change in annual electric usage from TOU rates. The specific load-shifting estimate by market segment is provided later in this section.

End of Exhibit G

EXHIBIT I: DEMAND MANAGEMENT INVESTIGATION IN THE SUTHERLAND & ST. GEORGE REGION OF

[5] Peak period is defined as 12 noon to 6 p.m. on weekdays during June through September.

SYDNEY (AUSTRALIA)

NOTE: THE FULL REPORT IS AVAILABLE ON THE PORTAL - ONLY AN EXECUTIVE OVERVIEW IS INCLUDED HERE (THE FULL REPORT IS 66 PAGES).

- **Executive Overview**
-
- Energetics was engaged by the Department Infrastructure, Planning and Natural Resources (DIPNR) to conduct investigations into the potential for reducing network electricity demand via a range of demand management (DM) measures in the Sutherland and St George region of Sydney.
-
- This report seeks to identify the potential demand reduction achievable in this area via implementation of:
-

• Power factory correction
• Standby generation
• Interruptible load
• Fuel switching, and
• Energy efficiency

-
- One or more of these measures can be employed to reduce network loads. In particular, when network demand constraints are forecast these measures can be implemented , often with incentive payments to customers, to enable augmentation of the local network to be deferred or avoided.
-
- Energetics was provided with summary 12-month energy consumption data and half-hourly interval data for 148 customer sites within the region, with peak electrical demand ranging from 150 kVA up to 5,000 kVA. A total of 125 of these sites were investigated during the course of the project, with 84% of customers approached by Energetics agreeing to participate. Other customers in the area, such as residential users, commercial and industrial customers with peak demand less than 150 kVA and commercial and industrial customers with peak demand in excess of 5,000 kVA, were not audited. The results from each site investigation, which identified potential peak summer and winter demand reduction from the above measures, were collated into a series of databases and analyzed to determine the overall potential for demand reduction from each measure.
-
-
- ***End of Exhibit I***