INTERNATIONAL ENERGY AGENCY
DEMAND SIDE MANAGEMENT PROGRAMME

TASK XIII: DEMAND RESPONSE RESOURCES

Estimating Demand Response Market Potential

Final Report

JULY 2005

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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. Two additional survey instruments are presented in Appendices B and D. 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 complete evaluation report is also presented in Appendix 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 Appendices 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 Appendix A. Most often residential DR program managers and commercial/industrial DR program managers were interviewed separately. In some cases utility rate department staff were 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.

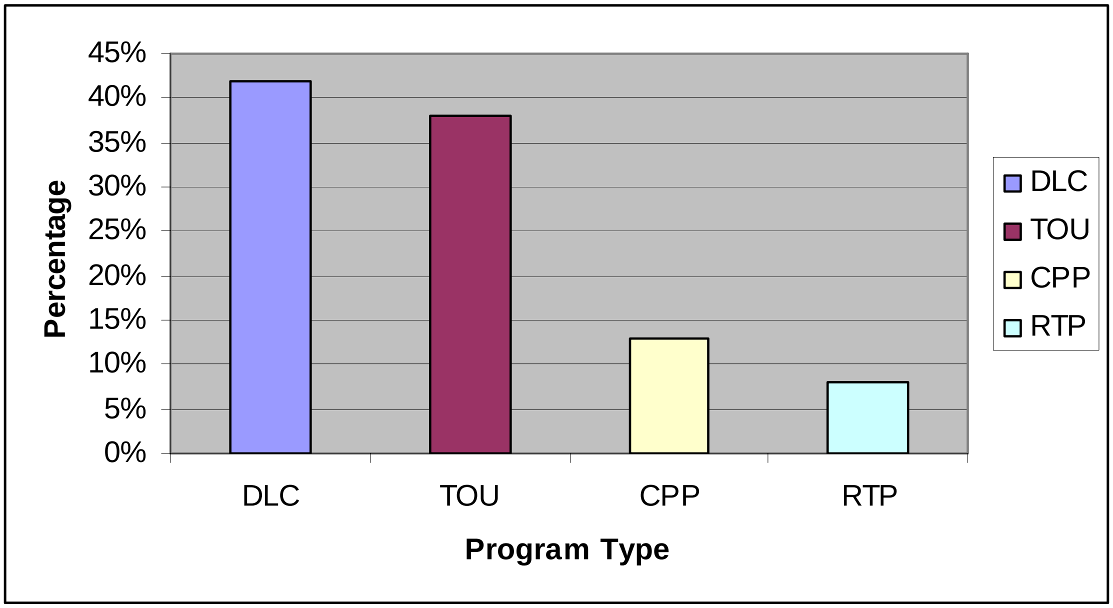
2. **Time-of-use (TOU) rates:** The most common type of TOU rates are “two-part” rates that charge customers a higher “on-peak” price than the standard flat utility rate during daytime hours, and a lower “off-peak” price during nighttime hours and weekends. Some utilities offer a “three-part” TOU rate, 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.

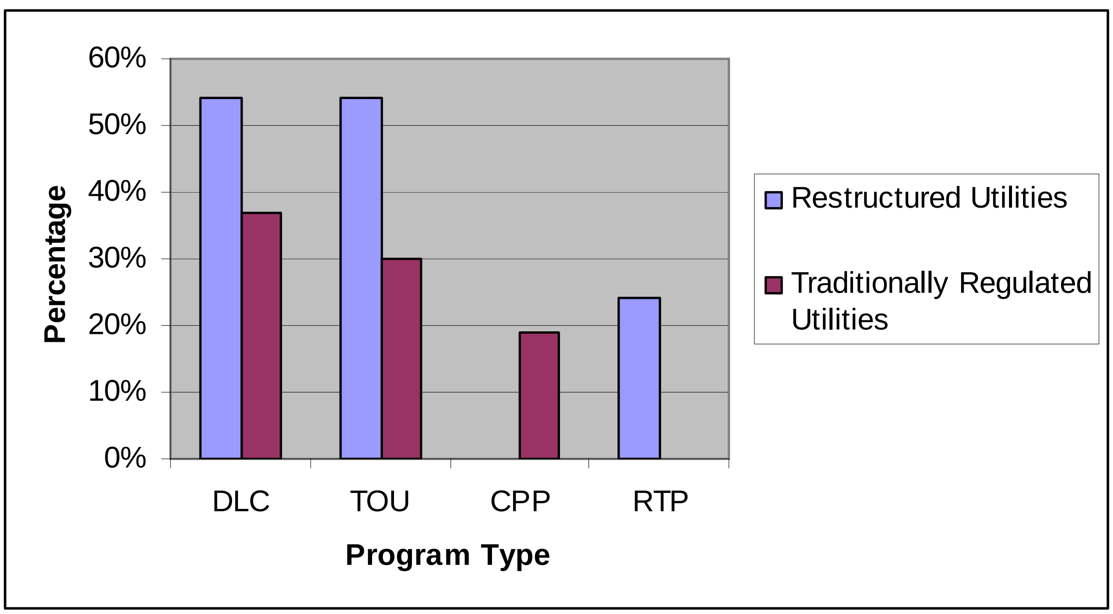
It is interesting to note that almost three-fourths (73%) of the utilities surveyed are conducting at least one type of DR program for residential customers. The most prevalent residential DR programs are DLC programs and two-part TOD rates, each conducted by about 40% of the utilities surveyed. Figure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

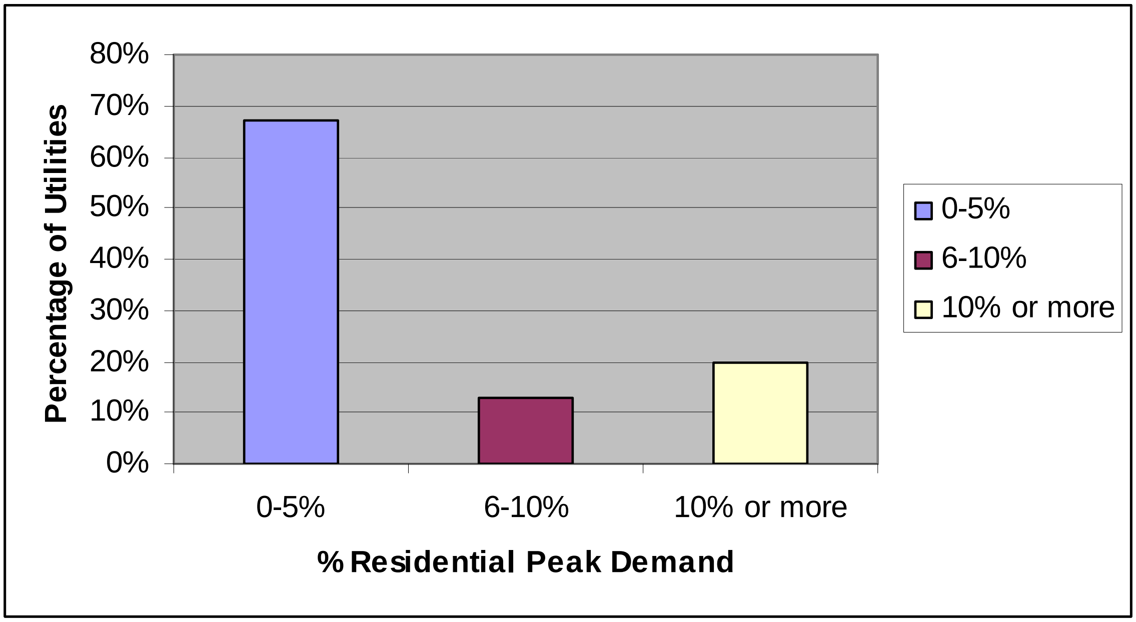
The primary benchmark used for residential DLC programs is the ratio of the programs' total peak demand reduction impact to the utilities' residential peak demand. This benchmark measures the significance of the DLC program to utilities, and provides an indicator that is normalized for the size of the 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.

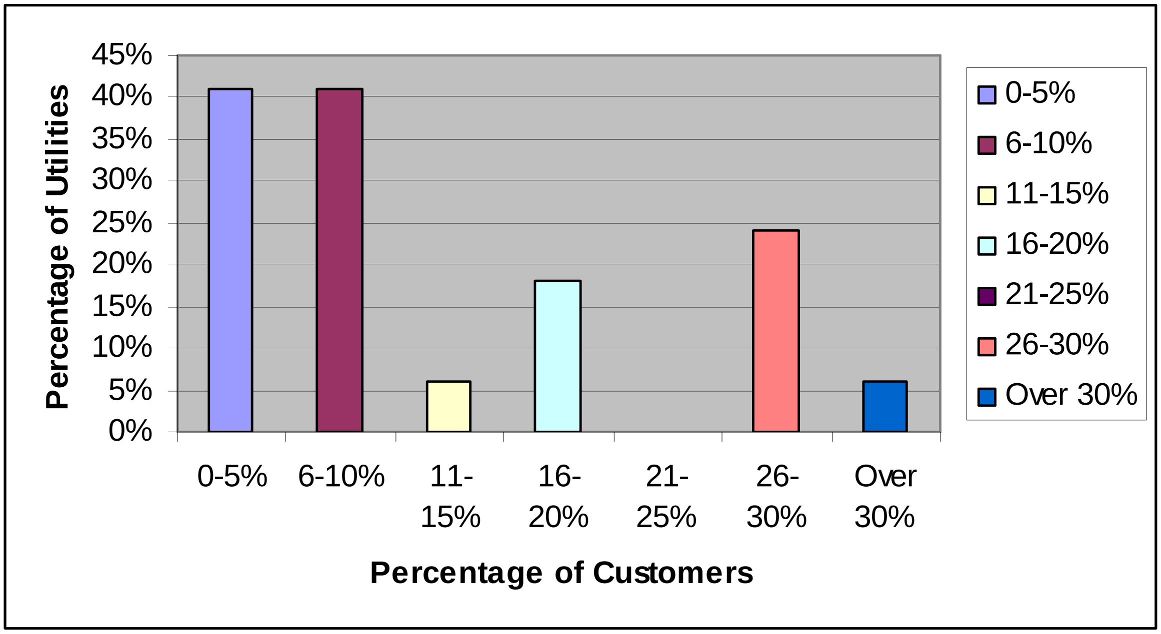
Those two factors explain why the program impacts of the utilities operating in restructured states are so much lower than the impacts for the traditionally regulated utilities. The mean DLC program starting year for the traditionally regulated utilities is 1985, compared to 1993 for utilities operating 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.

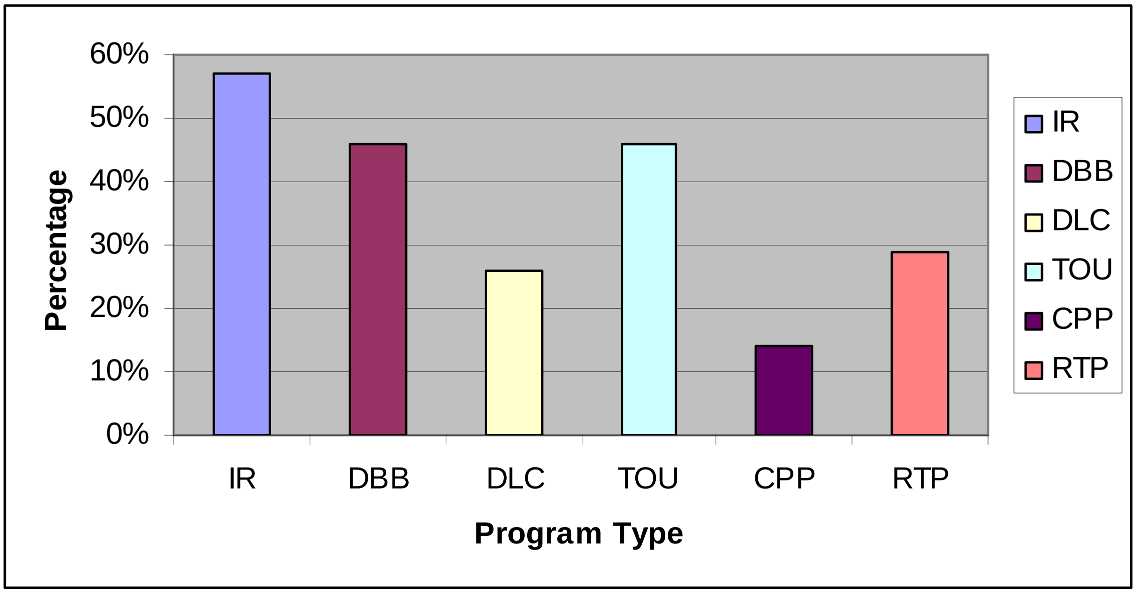
4. **Time-of-use (TOU) rates:** The most common type of TOU rates are "two-part" rates that charge customers a higher "on-peak" price than the standard "flat" utility rate during daytime hours, and a lower "off-peak" price during nighttime hours and weekends. Some utilities offer a "three-part" TOU rate, 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.

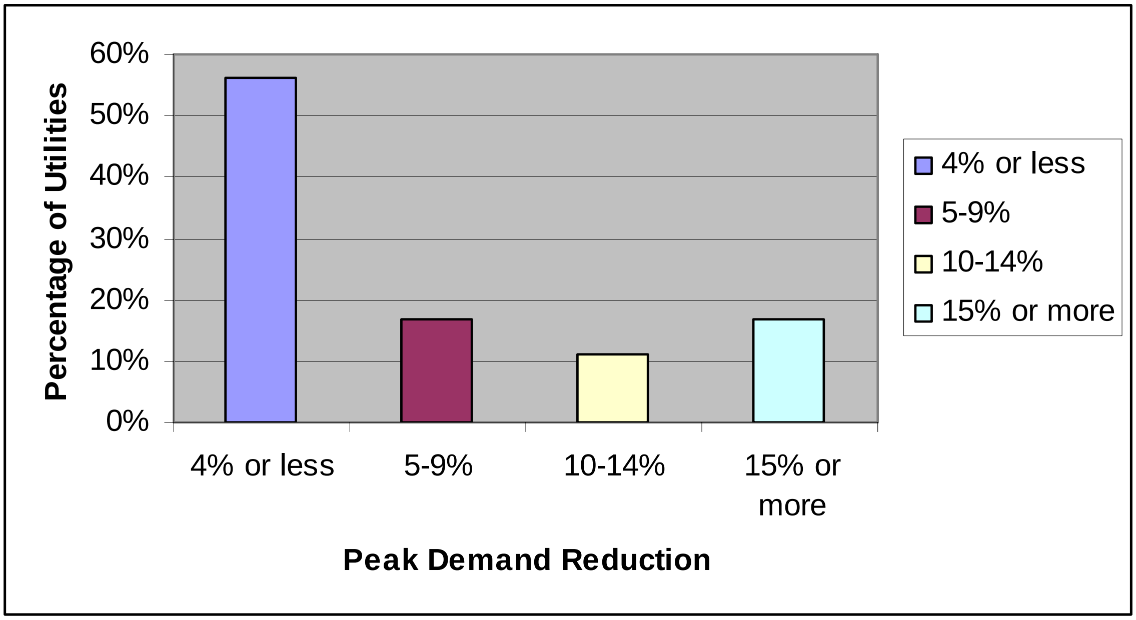
An additional 11% of utilities surveyed are able to reduce their C/I peak demands by 10-14% through their IR programs. These utilities have a broader base of program participation than most of the utilities with the largest program impacts.

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

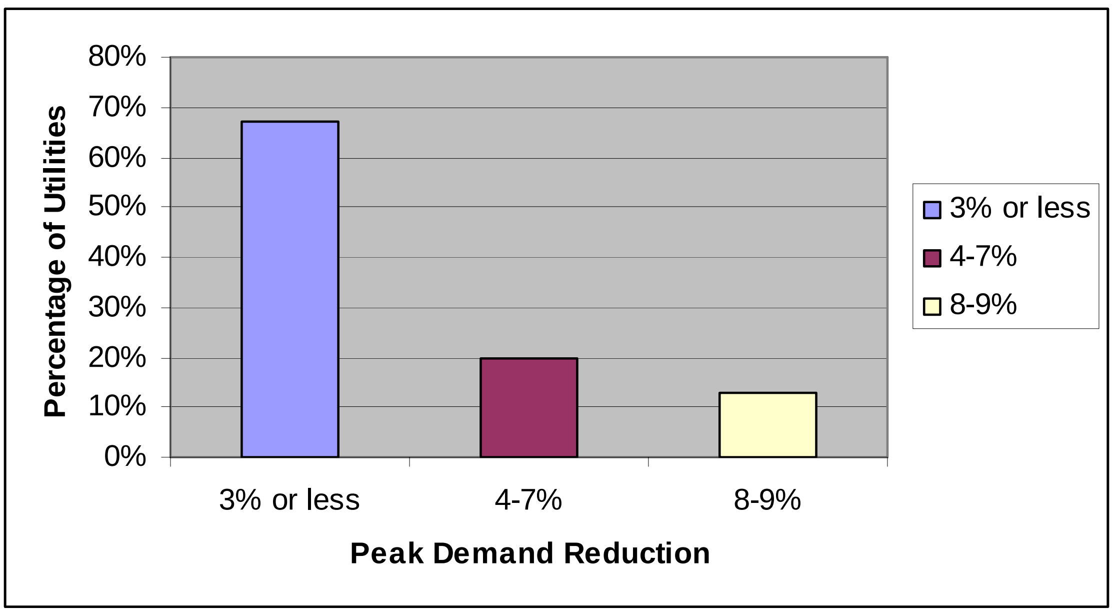
DBB programs are estimated to provide the largest peak demand impacts for about 20% of the utilities surveyed, and several additional utilities also estimate significant demand reduction impacts from their DBB programs. The top-performing programs have impacts that amount to 8-9% of utilities' C/I peak 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.

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

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 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 Appendix 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 Appendix C, followed by the survey instrument in Appendix D.

RESIDENTIAL DLC DR POTENTIAL TELEPHONE SURVEY

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

<u>Introduction</u>

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

Thank and end survey.

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:

1. 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.
2. 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.
3. 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 Appendices 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.