DISCUSSION PAPER

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The Power of Five Percent

How Dynamic Pricing Can Save $35 Billion in Electricity Costs

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THE INDUSTRY FACES AN IMMEDIATE PROBLEM

Demand for electricity continues to soar in the United States, pushed along in the short term by events such as last year's heat storm that broke records in every region of the country and in the long term by the continuing expansion and electrification of the US economy.

At the national level, the peak demand for electricity is projected to reach 757,000 MW during the coming summer.[1] According to the North American Electric Reliability Council (NERC), this number will grow by 19 percent over the next decade. However, since currently committed capacity is projected to grow only by six percent, the demand-supply balance could be significantly stressed in the nation's power markets.[2]

Compounding the problem is that customers are likely to face rising electricity bills in just about all parts of the country. Capacity costs and fuel costs are on an upward trend, decade-old rate freezes are coming off in several states and there is a strong likelihood that Congress will mandate a cap-and-trade system for reducing greenhouse gas emissions in the near future. This has led some experts to believe that the "rate base" for electricity, which represents the dollar value of assets in the power business, is likely to double in the next decade. During the past several months, speakers at a wide range of power industry conferences have noted that there is very little time to "build" our way out of the problem by simply expanding the nation's generation capacity and the associated power grid, i.e., the transmission and distribution system that delivers power from the generation plants to the nation's 138.4 million customers.[3]

A consensus is forming that the best way to ensure reliability and competitive functioning of markets is to deploy an integrated approach that combines traditional solutions involving the supply-side of the business with demand-side solutions that give customers the ability to control their usage, especially during times when the power system encounters critical conditions. Such conditions most often occur during a heat wave but they can also occur when a large generation unit trips or when the grid is hit by an emergency.

1. This is the non-coincident peak demand in the United States, obtained by adding the peak demands of individual power planning councils.
2. NERC, 2006 Long-Term Reliability Assessment, states, "Available capacity margins, which include only committed resources, are projected to drop below regional target levels in ERCOT, MRO, New England, RFC, and the Rocky Mountain and Canada areas of WECC in the next 2–3 years, with other portions of the Northeastern U.S., Southwest, and Western U.S. falling below target levels later in the ten-year period."
3. Of this number, 120.7 million are residential customers, 16.9 million are commercial customers and 0.7 million are industrial customers, according to the US Energy Information Administration. http://www.eia.doe.gov/cneaf/electricity/esr/table1.xls.

The demand for electricity is highly concentrated in the top one percent of hours. In most parts of the United States, these 80-100 hours account for roughly 8 to 12 percent of the maximum or peak demand. In California, they account for some 11 percent. In the 12 Midwestern and Northeastern states that form the PJM Interconnection, they account for 16 percent. In the Canadian province of Ontario, the top 32 hours account for 2,000 MW of demand out of a peak demand of 27,000 MW.

If a way can be found to shave off some of this peak demand, it would eliminate the need to install generation capacity that would be used less than a hundred hours a year. Such generating capacity is often gas fired and consists of combustion turbines, which is expensive since these turbines are idle for almost the entire year.

HOW DEMAND RESPONSE AND DYNAMIC PRICING CAN HELP DEAL WITH THE CHALLENGE

The fundamental idea behind demand response is to provide accurate price signals to customers that convey the true cost of power.[4] Since electricity cannot be stored and has to be consumed instantly, and since generation plants of varying efficiency are used to meet demand, the cost of power varies by time-of-day and day-of-year. This is true in markets that have been restructured as well as those that have not.

Once clear price signals are conveyed to customers, they can decide whether to continue buying power at higher prices or to curtail their usage during peak hours. This market-driven concept promotes economic efficiency in the consumption of electricity. It can also save substantial monies in the aggregate for society.

How much will be saved by demand response will depend on two things: first, how much peak load can be reduced by customers and second, how much generation (and related power delivery) investment and fuel can be offset by this load reduction. The first item itself depends on two things: how rapidly utilities and regulators move to install new pricing designs that provide the correct price signals to customers and how well customers respond to the price signals.

A prerequisite to the provision of dynamic pricing is the installation of advanced metering infrastructure (AMI). Depending on features and geography, AMI investment costs can range from $100 to $200 per meter but much of that cost can be recovered through operational benefits such as avoided meter reading costs, faster outage detection, improved customer service, better management of customer connects and disconnects, and improved distribution management.

In Northern and Central California, Pacific Gas and Electric Company that serves five million electric and four million gas customers estimates that 89 percent of its AMI investment of $1,700 million can be recovered through operational benefits.[5] The two investor-owned utilities in Southern California estimate that roughly half of their costs will be recovered through operational benefits.[6]

Many utilities have already installed AMI because they were able to recover their entire investment through op-

4. In addition to dynamic pricing, demand response can also be implemented by providing cash incentives to customers that encourage them to control usage. Examples include direct load control programs that target end uses such as central air conditioners and water heaters, interruptible and curtailable rates that target large customers and various forms of load curtailment that are practiced by independent system operators and regional transmission operators around the country. In this assessment, we focus exclusively on demand response as implemented through dynamic pricing programs. Such programs are triggered by economic as opposed to system reliability criteria. NERC estimates that about five percent of US peak load is currently enrolled in reliability-triggered programs. However, it is difficult to estimate the amount of capacity that would actually be available during an emergency.

5. California Public Utilities Commission, "Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure," July 20, 2006, No. Decision 05-06-028.

6. San Diego Gas and Electric estimates a cost of $572 million for its AMI system that would reach 1.4 million electric and 900,000 million gas customers. Southern California Edison has provided a preliminary estimate in excess of a billion dollars for its AMI system that would reach roughly 5.4 million customers.

erational benefits. According to a recent FERC report, AMI currently reaches six percent of electric meters in the US.[7] Certain states, such as Pennsylvania and Wisconsin, have AMI penetration rates in excess of 40 percent. AMI penetration rates are in the double digits in eight states.

However, most utilities with AMI system still do not have dynamic pricing designs in place. They, along with their state regulators, are uncertain whether customers will respond to such pricing signals. Some are also afraid of a customer backlash to potentially volatile prices. [8]

There is a good bit of skepticism that residential and small commercial and industrial customers, who constitute the vast majority of the nation's electricity users, will respond to dynamic pricing signals by lowering their demand during peak times. However, new experimental evidence from California and Illinois is beginning to make a dent in this skepticism.[9] This evidence is generally consistent with earlier results from pilots that were carried out in the late seventies and early eighties under the auspices of the US Department of Energy and the Federal Energy Administration.[10] It shows that, on average, customers will respond to higher prices by lowering usage during peak hours and by so doing, they will reduce their annual power bills.

In a $20 million pilot that involved some 2,500 residential and small commercial and industrial customers over a three-year period, California's three investor-owned utilities tested a variety of dynamic pricing designs. The experimental process involved a working group that was facilitated by the state's two regulatory commissions and involved dozens of interested parties and stakeholders, some opposed to dynamic pricing and some supporting it.

The California experiment provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by two or four degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion and represent the state-of-the art.

The experiment showed that the average Californian customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were five times higher than their standard tariff.[11] Customers who had a smart thermostat reduced their load about twice as much, by 27 percent. And those who had the gateway system reduced their load by 43 percent.[12]

The experiment also showed that customers did not respond equally to the price signals. Some responded a lot and some did not respond at all. In fact, about 80 percent of the collective demand response came from just 30 percent of the customers. Of course, what matters in terms of demand response system benefits is the response of all customers in the aggregate, not the response of each individual customer. [13]

7. FERC, "Assessment of Demand Response and Advanced Metering," Staff Report, August 2006.

8. For a discussion of the myriad reasons for this hesitancy, see Ahmad Faruqui, "Breaking out of the Bubble," Public Utilities Fortnightly, March 2007.

9. Several other pilot programs are underway at this writing in the United States and Canada. These include those in the District of Columbia, Hawaii, Idaho, Missouri, New Jersey and the Canadian province of Ontario. However, results are not yet available from these pilots. New pilots are being planned, such as those in Baltimore, Maryland.

10. The results from that earlier generation of pilots are summarized in Ahmad Faruqui and J. Robert Malko, "Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing," Energy: The International Journal, 1983.

11. The 13 percent drop occurred during the six months of the summer season from May to September. Responses during the inner summer months of June-August were a percentage point higher. The 14 percent number might be more applicable during critical-peak conditions.

12. Ahmad Faruqui, "Pricing Programs: Time-of-Use and Real Time," in Encyclopedia of Energy Engineering, 2007, forthcoming.

13. The findings of the California pricing experiment are consistent with those of other pricing experiments that have been carried out over the past three decades, both in the US and abroad. For a recent survey, consult Chris King and Sanjoy Chatterjee, "Predicting California Demand Response," Public Utilities Fortnightly, July 1, 2003.

The experiment also provided evidence on the response of small commercial and industrial customers. In addition, non-experimental evidence has been collected for large commercial and industrial customers, both in California and in other parts of the country. This allows us to make an initial projection of the likely impact of dynamic pricing on US peak demand.

HOW MUCH DEMAND RESPONSE CAN BE ACHIEVED THROUGH DYNAMIC PRICING?

The first projection is an estimate of technical potential. It measures what would happen if all customers used the best available DR technology. In the residential class, this is the gateway system, which has the potential for lowering peak demand by 43 percent. In the commercial and industrial classes, automatic DR programs that control multiple end-use loads and leverage the energy management system that is installed in most facilities are projected to reduce demand by 13 percent.[14] By taking a weighted average over all customer classes, we arrive at an estimate of 22.9 percent for the technical potential of demand response.[15]

The second projection is an estimate of economic potential. It measures what would happen if all customers used a cost-effective combination of technologies rather than the best available technologies. Our estimate of the economic potential for demand reduction through pricing-based DR programs is 11.5 percent.

To illustrate this computation for the residential class, recall that customers in the California experiment without an enabling technology lowered their peak usage by 13 percent. Those with a smart thermostat lowered it by 27 percent and those with the gateway system lowered it by 43 percent. If 70 percent of the customers chose no enabling technology, 20 percent chose the smart thermostat and 10 percent chose the gateway system, this would yield a weighted average estimate of 18.8 percent for the residential class. Corresponding values for the commercial and industrial classes are 7.3 percent and 9.4 percent.

The third projection is an estimate of market potential. It measures what would happen if a cost-effective combination of technologies is accepted by a realistic number of customers in the market place. It differs from economic potential that assumes that all customers accept dynamic pricing. Thus, the key unknown in estimating market potential is the number of participating customers. This, of course, depends on the conditions under which dynamic pricing is offered to customers.

If dynamic pricing is made the default rate, as it has been made in restructured states for large customers, a larger fraction of customers would be expected to stay on it than if it is offered on an optional basis. The limited literature on the topic suggests that about 80 percent would stay on dynamic pricing if it is offered as the default rate and that a substantially smaller number, perhaps 20 percent, would select in on a voluntary basis. In our analysis, we assume that the actual number is likely to be somewhere in the middle. This yields an estimate that DR programs based on dynamic pricing could reduce peak demand by approximately five percent. [16]

WHAT IS THE VALUE OF A FIVE PERCENT DEMAND RESPONSE?

What is the value of a five percent reduction in demand during critical periods? Several types of benefits can be identified even though it is not possible to quantify all of these in a preliminary projection. First and foremost is the reduction in the need to install peaking generation

14. Much higher responses are possible in specific facilities that have time-flexible production processes, energy storage systems and back-up generation. Since these are highly facility-specific, we have not included them in our estimate of technical potential.

15. Details of all the computations made in this report are presented in the appendix.

16. Recognizing the uncertainty in such an estimate, we have used probabilistic simulation techniques on the key input variables that have gone into its computation. The specific technique we have used is called Monte Carlo simulation. We find that there is a 90 percent chance that the market potential will be at least 2.6 percent and 10 percent chance that it will be at least 7.7 percent. There is a 50 percent probability that it will be at least 5.0 percent capacity. This is a long run benefit and consists of the sum of avoided capacity and energy costs. It can be readily estimated based on the capacity cost of a combustion turbine. The second benefit is the avoided energy costs that are associated with the reduced peak load. Third is the reduction in transmission and distribution capacity. This is also a long-run benefit but is harder to quantify and is very dependent on system configurations that vary regionally.

In order to quantify the avoided capacity cost, we first quantify the amount of capacity that will be avoided by a five percent reduction in peak demand and then value it. A five percent reduction in US peak demand of 757,056 MW amounts to 37,853 MW of peak demand. The amount of peaking capacity that is needed to meet this peak demand can be computed by allowing for a reserve margin of 15 percent and line losses of eight percent. This turns out to be 47,013 MW or roughly 625 combustion turbines.[17] A conservative value of the avoided cost of capacity is $52/kW-year.[18] Thus, the total value of avoided capacity costs is $2.4 billion per year.

Using the relationship that was observed between annual capacity and energy benefits in a recent PJM analysis of demand response, the annual value of avoided energy costs is estimated at $300 million.[19]

In addition, there would be a reduction in transmission and distribution capacity needs. As noted earlier, they are system-dependent and much harder to estimate. However, they are unlikely to be zero. A conservative estimate puts them at 10 percent of the savings in generation capacity and energy costs.[20] Using this estimate, we derive an estimate of $275 million per year for savings in transmission and distribution costs.

Adding up these three components yields long-run benefits of demand response of $3 billion per year, as shown in Figure 1. [21] Over a 20-year horizon, these represent a discounted present value of $35 billion.[22]

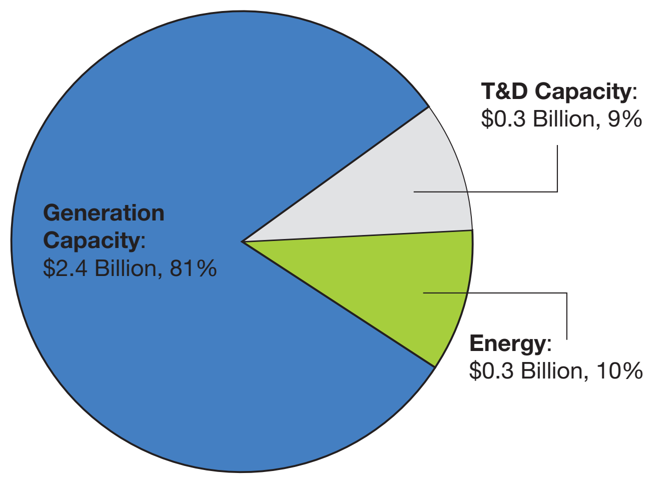

Figure 1: Annual Long-Run Benefis of Demand Response

17. These turbines come in sizes generally ranging from 50 MW to 100 MW.

18. PG&E's filing with the CPUC on AMI uses two numbers, $85/kW-year recommended by the CPUC in an ALJ ruling and $52/kW-year, which is derived by subtracting the revenue stream associated with the sale of energy from the combustion turbine.

19. Sam Newell and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), The Brattle Group, January 29, 2007 ("PJM-MADRI Demand Response Study").

20. This estimate is based the filing of PG&E with the CPUC on AMI. From a national perspective, we cite the US Energy Information Administration's estimate that transmission and distribution costs account for some 36 percent of electricity costs. Source: Electricity Power Annual, 2007, using data from 2005.

21. We have estimated the uncertainty in this estimate by applying Monte Carlo simulations to likely ranges of the input variables. Across a wide range of assumptions, we find that there is a 90 percent probability that the estimate is at least $1.5 billion and a 10 percent probability that it is at least $5.3 billion. There is a 50 percent probability that it is higher than $3.1 billion.

22. Using Monte Carlo simulations, we find that there is a 90 percent probability that the estimate is at least $18 billion and a 10% probability that it is at least $61 billion. There is a 50 percent probability that it is higher than $37 billion.

Pursuing Short-run Benefits

These long run benefits of demand response are properly viewed as an efficiency gain, since they involve real savings in total resource costs on average over time. However, there will also be an immediate reduction in the wholesale market prices for energy and capacity caused by the reduction of demand during critical times. This is a short run benefit that can be quantified through market simulations.[23] In regions that are capacity constrained, such benefits could be higher than the benefits associated with long-term avoided costs. These price mitigation benefits would persist only temporarily following the institution of dynamic pricing programs until generation capacity adjusts to the new load profile.

Nevertheless, despite their temporary nature, these short-run benefits can significantly add to the present value of demand response programs by being able to address quickly challenging wholesale market conditions that exist in regions with scarce supply. For example, our PJM-MADRI Demand Response Study showed that demand response programs that would curtail the peak load in eastern PJM by only approximately 1,100 MW (or three percent of five load zones in eastern PJM) would have produced short-term customer benefits ranging from $150 million to $300 million in 2005. Scaled up to a five percent load reduction for the entire U.S., this would translate to between $5 billion and $10 billion per year, or approximately 170 percent to 340 percent of the long-term benefit quantified above.

Clearly, the degree of supply-constrained market conditions in eastern PJM does not exist nationwide. But these results show that pursuing demand response initiatives first in markets that benefit the most from these programs creates additional benefits that increase the overall present value of the investment.

The Cost-Benefit Ratio of Investing in Dynamic Pricing?

How do the quantified long-term benefits compare to the cost of installing AMI, a pre-condition for dynamic pricing? As was mentioned earlier in this paper, a large portion of the cost of AMI can be recovered through operational benefits, such as savings in meter reader costs and faster outage detection. However, the prior experience of many utilities is that there is still a “gap” between AMI costs and the operational savings.

Assuming an approximate cost of $200 per meter, which is the upper end of expert opinion, and assuming that advanced meters are installed for the remaining 94 percent of the 138.4 million electricity customers in the U.S. that currently do not have such meters, we estimate that an investment of $26 billion will be necessary to install AMI in the entire country. If 50 percent to 80 percent of these costs are recovered through operational benefits, the remaining cost of AMI is between $5.2 billion and $13.0 billion. Thus, the net costs of AMI that would need to be recovered through demand response benefits are only 15 percent to 37 percent of the $35 billion in long-run benefits, making AMI a highly cost-effective investment from a national perspective.

OTHER ISSUES

Demand response is likely to have other benefits as well. These would include more competitive energy and capacity markets, reduced price volatility, the provision of insurance against extreme events that have not been captured in long-term resource planning scenarios, fewer environmental emissions during peak periods, improved system reliability resulting in fewer blackouts and brownouts, and AMI-based enhanced levels of customer service. In this assessment, we have not quantified any of these benefits.[24]

23. For a description of such a simulation, see our PJM-MADRI Demand Response Study.
24. For a qualitative discussion of these benefits, see our PJM-MADRI Demand Response Study.

Some additional costs would also be incurred as utilities change their billing systems and institute mechanisms for communicating the dynamic price signals to customers. All of these variables will need to be factored in and quantified in the final decision to move ahead with DR.

Finally, we recognize that there are several barriers to the institution of dynamic pricing mechanisms. These barriers involve regulatory policies and rate freezes, customers' and policy makers' apprehensions about price volatility, and perceptions about the availability of enabling technologies. Unless these barriers are addressed, the full potential of demand response will not be realized. For example, the state of California set a goal of five percent for economically triggered demand response programs for the year 2007. However, only half of this goal is likely to be realized this year. [25]

CONCLUSIONS

The potential impact of demand response is large and significant. Using best available technologies, customers could potentially lower the national peak demand by 22.9 percent. Using a cost-effective mix of technologies, peak demand could be lowered by 11.5 percent. Against this backdrop, we estimate that the market potential of demand response is five percent based on realistically achievable penetration rates.

Even a five percent drop in peak demand can yield substantial savings in generation, transmission and distribution costs. We estimate that this five percent reduction would eliminate the need for installing and running some 625 infrequently used peaking power plants and associated power delivery infrastructure. At the national level, this translates into a savings of $3 billion a year or $35 billion over the next two decades.

Even without counting other benefits, such as the lowering of wholesale prices in supply-constrained markets, improved reliability, or enhanced customer service, the benefits of demand response are large enough to warrant serious attention by utilities and regulatory commissions throughout the United States.

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governments around the world.

We have offices in Cambridge, Massachusetts; San Francisco; Washington, DC; Brussels; and London.

25. For a detailed discussion of barriers and possible remedies, see "The State of Demand Response in California," Draft Consultant Report, California Energy Commission, April 2007.

APPENDIX: ESTIMATING DEMAND RESPONSE BENEFITS

This appendix describes the assumptions and calculations that were used to arrive at the estimated $35 billion in potential national benefits of demand response.

The allocations of peak demand to the residential, commercial, and industrial sectors are based on a review of EIA and EPRI documents containing energy shares and load shapes by sector.

Table 1: Peak Demand Allocation by Sector

Sector	Peak Demand Allocation	% of Total
Residential	251 GW	33%
Commercial	351 GW	46%
Industrial	155 GW	20%
Total	**757 GW**	**100%**

The penetration rate of enabling technologies within the three sectors is a projection based on general industry knowledge and experience. The average customer-level peak reduction that can be achieved through each of these technologies, when paired with a CPP rate, comes primarily from the Statewide Pricing Pilot and studies conducted by the Demand Response Research Center.

Table 2: Demand Response by Sector and Technology

Technology	In-Class Allocation	Customer Response	Source
Residential			
No Technology	70%	13%	2005 CRA SPP Res. Report
Enabling Technology	20%	27%	2005 CRA SPP Res. Report
Gateway	10%	43%	2006 RMI ADRS Report
Weighted Avg		*18.8%*	
Commercial			
No Technology	60%	5%	2006 CRA SPP C&I Report
Enabling Technology	30%	10%	2006 CRA SPP C&I Report
Auto DR	10%	13%	DRRC
Weighted Avg		*7.3%*	
Industrial			
CPP	60%	7%	2006 Quantum SPP Report
Auto DR	40%	13%	DRRC
Weighted Avg		*9.4%*	

The same sectoral allocation was used in all three projections of DR potential (as shown in Table 1). Both the technical potential and economic potential projections assume 100 percent participation by all sectors, while the market potential projection assumes roughly 43 percent participation in each sector. Customer-level demand response for technical potential is assumed to be based on the technology that allows for the largest response in each sector. In estimating the economic and market potential, a weighted average is used, based on the technology market penetration assumptions shown in Table 2. These assumptions lead to the total demand reduction estimate for each sector. Calculating a weighted average using each sector's share of the total population produces the final projections of technical, economic, and market potential for California as shown in Table 3.

Table 3: Assumptions in Calculation of DR Potential

	Technical Potential	Economic Potential	Market Potential
Sector Allocation to Total Population			
Residential	33.2%	33.2%	33.2%
Commercial	46.4%	46.4%	46.4%
Industrial	20.5%	20.5%	20.5%
Total	**100.0%**	**100.0%**	**100.0%**
Sector Participation Rate			
Residential	100.0%	100.0%	43.3%
Commercial	100.0%	100.0%	43.3%
Industrial	100.0%	100.0%	43.3%
Total	**100.0%**	**100.0%**	**43.3%**
Customer Demand Response			
Residential	43.0%	18.8%	18.8%
Commercial	13.0%	7.3%	7.3%
Industrial	13.0%	9.4%	9.4%
Total	**22.9%**	**11.5%**	**11.5%**
Total Demand Reduction Estimate			
Residential	43.0%	18.8%	8.1%
Commercial	13.0%	7.3%	3.2%
Industrial	13.0%	9.4%	4.1%
Total	**22.9%**	**11.5%**	**5.0%**

The avoided cost of generating capacity, electricity generation, and T&D capacity are all components of the financial benefits of DR. The specific calculations used to arrive at the final estimates of the present value of a five percent peak demand reduction are described in Table 4.

Table 4: Assumptions in Calculation of Present Value of DR Financial Benefits

	Assumption/Calculation	Value	Units	Source
[A]	2007 US non-coincident peak demand forecast	757,056	MW	2006 NERC report
[B]	Market potential of DR	5%	% of peak	Calculation of Market Potential
[C]	Peak demand reduction	37,853	MW	[A] * [B]
[D]	Reserve margin	15%	% of peak	Generally accepted industry practice
[E]	Line losses	8%	% of peak	Generally accepted industry practice
[F]	System-level MW reduction	47,013	MW	[C] * (1 + [D]) * (1 + [E])
[G]	Value of capacity	52	$/kW-yr	2006 PG&E AMI Filing
[H]	Value of capacity	52,000	$/MW-yr	[G] * 1,000
[I]	Total avoided capacity cost	2,445	Million $/year	[F] * [H] / 1,000,000
[J]	Peak demand growth rate	2%	% per year	Assumption
[K]	Annual discount rate	8%	% per year	Assumption
[L]	Study time horizon	20	years	Assumption
[M]	PV of $1 annuity for 20 years	11.58	$	Assumption
[N]	Energy % of generation capacity cost	12%	% of NPV	2006 Brattle DR Study for MADRI/PJM
[O]	T&D % of energy and generation capacity cost	10%	% of NPV	2006 PG&E AMI Filing
[P]	PV avoided generation capacity cost	28,310	Million $	[I] * [M]
[Q]	PV avoided energy cost	3,490	Million $	[N] * [P]
[R]	PV avoided T&D capacity cost	3,180	Million $	[O] * [P]
[S]	PV of total avoided cost	34,980	Million $	[P] + [Q] + [R]

Sources:

- 2005 CRA Residential SPP Report: CRA International, *Impact Evaluation of the California Statewide Pricing Pilot*, March 16, 2005.
- 2006 Brattle DR Study for MADRI/PJM: Newell, Sam and Frank Felder, *Quantifying Demand Response Benefits in PJM*, Study Report Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.
- 2006 CRA C&I SPP Report: CRA International, *California's Statewide Pricing Pilot: Commercial & Industrial Analysis Update*, June 28, 2006.
- 2006 NERC Report: NERC, "2006 Long-Term Reliability Assessment," October 2006, p. 125.
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