BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing U 39 E	Rulemaking 02-06-001 (filed June 6, 2002)

PRELIMINARY AMI BUSINESS CASE ANALYSIS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E)

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Pursuant to the July 21, 2004 "Administrative Law Judge And Assigned Commissioner's Ruling Adopting A Business Case Analysis Framework For Advanced Metering Infrastructure" (July 21 ACR),[1] Pacific Gas and Electric Company (PG&E) presents in this filing PG&E's preliminary business case analysis of Advanced Metering Infrastructure (AMI) deployment.[2]

I. EXECUTIVE SUMMARY

A. PG&E's Approach To AMI and This Preliminary Analysis

PG&E believes that AMI has the potential to deliver significant benefits to the State of California, to PG&E's customers, and to PG&E's business operations. AMI can be a powerful

[1] On June 6, 2002, the CPUC issued this Order Instituting Rulemaking (OIR) on policies and practices for advanced metering, demand response, and dynamic pricing (Docket No. R. 02-06-001.) In Phase 1 of the OIR proceeding, the CPUC adopted two decisions (D.03-03-036 and D.03-06-032 in March and June 2003, respectively). The first decision approved a statewide pricing pilot (SPP) to test critical peak prices and time-of-use rates for small commercial (< 200 kW peak demand) and residential customers. The SPP is currently underway, having begun July 1, 2003, and will continue through Summer 2004. The second decision adopted long-term state demand response goals and various demand response programs for large commercial customers (> 200 kW). These large customer programs are now going into effect. This filing deals with advanced metering for customers below 200 kW.

[2] This filing consists of a non-confidential part that generally describes the analysis, recommendations, and next steps. The detailed quantified outcome of each business case scenario is included in a confidential appendix (Appendix B) that is being filed under seal. The purpose of this approach is to protect the commercial sensitivity of PG&E's detailed business case analysis. Revealing this analysis to vendors could compromise PG&E's ability to negotiate the best contracts. PG&E therefore requests that the Commission adopt a non-disclosure agreement (NDA), attached to a separate Motion for Protective Order filed simultaneously with this filing, under which only non-vendor interests would have access to the confidential appendix.

tool to help avoid a future energy crisis, capture operational efficiencies, and improve customer satisfaction. By enabling dynamic rates, AMI can facilitate the implementation of a portfolio of innovative electric pricing and demand response programs designed to lower procurement costs, defer transmission and distribution upgrades, and improve reliability. Customer benefits include quicker and more accurate outage information, response and restoration; more timely and detailed energy usage and energy management information; and more customer choice through enhanced rate and tariff options. Operational benefits include more efficient meter reading; reduced field visits and customer calls; improved billing accuracy; better outage information; improved cash flow; and more efficient asset management. PG&E is optimistic that AMI can be a far-reaching tool for enhancing both services and operational efficiency into the future.

To further explore the potential for deploying AMI, on September 27, 2004, PG&E issued a Request for Proposals (RFP) seeking proposals from firms to provide AMI products and services. Responses are due November 10, 2004. It is PG&E's intent to obtain firm price proposals that will enable it to identify its best AMI deployment strategy for presentation to its management and to the Commission and to negotiate contracts with selected suppliers. If PG&E determines to enter into any contracts prior to Commission approval of the AMI project, those contracts will be contingent on Commission approval of the AMI project. Implementation of the AMI project will be subject to approval by both the Commission and PG&E's management,[3] and assumes establishment by the Commission of suitable cost recovery mechanisms allowing timely recovery of AMI deployment costs.

Regarding the business case analysis presented in this filing, PG&E notes two important caveats. First, while PG&E has conducted as thorough an analysis as is possible at this time, this

[3] Including approval by both the PG&E Board of Directors and the PG&E Corporation Board of Directors.

analysis is still preliminary. The costs and benefits will be subject to revision as a result of the RFP, additional data from the Statewide Pricing Pilot, and as other information and analysis becomes available. PG&E therefore makes no final recommendation at this preliminary stage and continues to refine its analysis to determine its preferred AMI rollout scenario to present to the Commission in a future application as directed in the July 21 ACR.

Second, while quantified cost-benefit analysis is the primary tool for evaluating AMI, it should not be the only consideration by the Commission in deciding whether AMI is in the public interest. The costs and the potential benefits of the AMI project are inherently uncertain, and difficult to quantify as is the case with any new technology. All the ways in which this long-term technology investment could change utility operations and deliver benefits to customers and the State cannot be predicted in advance. For these reasons, while cost-benefit analysis should be the primary deciding factor, it should not be the only consideration.

B. Summary Of Preliminary Business Case Analysis

PG&E analyzed nineteen AMI deployment cases.[4] These are summarized in section VI, below, of this filing. Seventeen of the cases are based on the scenarios and rate assumptions requested by the Commission in the July 21 ACR; two of the cases analyze an additional default tariff option not specified by the Commission (so-called "CPP-Pure"[5]). All of the cases assume replacement of both electric and gas meters. The first five cases do not involve demand response tariffs: case 1 is a "base" case assuming no AMI; cases 2- 5 are "operational cases" assuming operational benefits of deploying AMI without demand response tariffs. The remaining cases

[4] PG&E has numbered these cases "1" through "19" for ease of reference.

[5] This is a Critical Peak Pricing (CPP) tariff that has a flat rate in all time periods of the year except for the CPP periods on the CPP days. Preliminary feedback from focus groups conducted during the SPP suggests that customers would prefer a CPP-Pure rate structure. The ACR provides CPP-P as an "opt-in" tariff under various scenarios. PG&E's additional cases analyze CPP-P as a default tariff, i.e., on an "opt-out" basis.

assume some kind of demand response tariffs. Analyzing each case involves the following steps:

- *Define case parameters*:
    - Full or partial deployment
    - Current tariffs and demand response tariffs (if dynamic rates are included)
    - Opt-in or opt-out (if dynamic rates are included)
    - Enabling technology or not (if dynamic rates are included)
- *Estimate costs of deployment*. These are currently based on Request for Information (RFI) responses,[6] internal estimates, and queries to the vendor community. These costs are preliminary and subject to revision following PG&E's RFP process.
- *Estimate operational benefits*. Operational benefits to PG&E are estimated using internal business experience and judgment, and industry experience. Again, these estimates are preliminary and will be revised after the RFP process and after PG&E further refines its analysis.
- *Estimate ranges of demand response benefits*. The estimated MW response is determined using a model constructed by PG&E's consultant, Charles River Associates (CRA). The model utilizes customer price elasticities to predict the change in energy use by time period. For the residential sector analysis, the price elasticities are based on analysis to date of data from the Statewide Pricing Pilot (SPP). For the small commercial and industrial customers (with demands under 200 kW[7]), the elasticities are largely based on previous studies.[8] Estimates of

[6] This was a preliminary AMI RFI PG&E issued on January 9, 2004.

[7] PG&E's preliminary business case analysis does not include customers with demands greater than 200 kW.

customer participation in the demand reduction tariffs (i.e., percentages of customers who "opt-out" of rates or "opt-in" to rates) are based on a combination of expert judgment and on the research conducted by Momentum Market Intelligence (MMI) as part of the SPP. Uncertainty is addressed by developing a distribution of impacts using a combination of Monte Carlo analysis for the elasticity estimates and scenario analysis for the participation rates. PG&E stresses that the demand response benefits are highly speculative: they depend heavily on the dynamic rate structures adopted by the Commission, participation rates (which depend on demand response rate structures and default rates), and customer behavior. The MW demand response benefits are valued using the $85/kW-year assumption provided by the Commission in the July 21 ACR. However, the avoided cost valuation of demand response is still an open question.

- *Quantify customer benefits to the extent possible*.
- *Compare costs and benefits:* NPV of costs – in the form of a tax-adjusted utility revenue requirement -- to NPV of benefits over the life of the assets. This comparison is similar to the so-called "Utility Cost" test.[9]

Based on PG&E's preliminary analysis (a summary table of all case results is found in Section VI below), five of the 19 AMI deployment scenarios cover the "break-even" range, with net benefits in the high case greater than zero and in the low case less than zero. The cases

[8] For this sector, the SPP results were deemed less reliable than using the results from previously published studies.

[9] The April 14, 2004 Staff Report on a "Recommended Analysis Framework for the Business Case Analysis of Advanced Metering Infrastructure," on which the July 21 ACR is based, states: "Three different perspectives needed to be considered in the analysis - utility, customer, and societal." PG&E believes it has complied with this direction by analyzing all benefits listed in the ACR, including utility, customer, and demand response benefits. All quantifiable benefits have been included in PG&E's cost benefit test. However, PG&E has not presented a "Total Resource Cost" test or a "Ratepayer Impact" test in this preliminary analysis.

exhibiting the highest demand response benefits are those with the most customers on dynamic rates, i.e., where all customers are placed on Critical Peak Pricing (CPP) tariffs, with the option to "opt-out" of the rate. This result is driven by the assumption that 60 to 90 percent of customers will remain on the CPP tariffs over time.[10] In contrast, the opt-in cases (where customers must volunteer or elect to go on the CPP tariffs) show much lower demand response benefits, because far fewer customers are expected to be on the CPP tariffs if CPP is not the default rate.

The demand response benefits from time-of-use (TOU) rates are much lower than the expected benefits under the CPP tariffs, whether the TOU rates are offered on an opt-in or an opt-out basis, because the load reduction per customer from the TOU rate is much lower than the load reduction per customer from the CPP tariffs.

Finally, the results show that a full deployment of AMI offers a higher potential for net benefits, and a wider range of potential outcomes than a partial rollout. This is largely due to fixed costs that are spread over fewer meters in a partial deployment than under full deployment, offsetting the higher per customer demand response benefits from the partial deployment.

PG&E is not recommending, however, that any scenario be dismissed out of hand simply because of relatively low demand response benefits. These results are based on preliminary analysis that can change significantly based on a variety of factors including: results of PG&E's RFP; summer 2004 SPP demand response data; more precise internal evaluation of operational costs and savings; and further consideration of the value of demand response capacity. In its application, PG&E will recommend the case that it believes most closely meets all appropriate

[10] Although the "opt-out" percentage is very uncertain, it is based on the studies conducted by MMI that suggest a large proportion of customers either are unaware of an alternative, don't want to take a risk by choosing an alternative, or have high switching costs.

regulatory and business criteria.

PG&E believes, moreover, that the realization of the demand response benefits should not be the sole driving criteria of whether AMI is in the public interest. AMI benefits also include operational benefits, options and choices for customers, and a powerful policy tool for the Commission. One of its most valuable uses may prove to be during a future energy shortage or price spike. Many benefits, especially the value of AMI to individual customers, are un-quantifiable either due to lack of experience with AMI or because the value can accrue as a societal benefit rather than as a direct rate savings. For these reasons, PG&E believes no hard and fast conclusions about the viability of any specific AMI rollout strategy should be drawn from these preliminary results.

C. Next Steps

Deployment of AMI starting in 2006 (PG&E's current working assumption) represents an aggressive schedule that will require expedited Commission approval of the project. PG&E intends to work with the Commission, the California Energy Commission (CEC) and other stakeholders to ensure that a regulatory process and schedule for AMI is developed that meets all regulatory and business criteria, including the needs of suppliers. Such a schedule must balance the timing of the RFP and contracting process, the time necessary for the Commission to convene a hearing and to review PG&E's AMI application, and the lead times, cash flow, and cost recovery requirements of a major capital project. PG&E believes a realistic schedule can be developed meeting all these requirements. Prior to the current December 15, 2004, PG&E intends to file a motion in this docket proposing a schedule.

II. DESCRIPTION OF CASES, SCENARIOS, AND ASSUMPTIONS

This section describes the cases and scenarios set forth in the ACR and analyzed by PG&E. The ACR requested 17 cases; however, PG&E has analyzed two additional cases (19 in all) to illustrate other rate design options.[11]

The following table, similar to the table on p. 10 of Attachment A of the ACR, summarizes the cases and provides a cross reference to PG&E's attached case/scenario analysis (Appendix B). The rates assumed by PG&E for this analysis are described in Appendix D.

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[11] The analysis results of the 19 cases are summarized on pages 31-32 in Section VI below.

	SCENARIOS					
TARIFF ASSUMPTIONS	***Required***	***Required***	***Required***	***Required***	***Required***	***Utility Option***
Opt- Out Default Tariff, i.e., customer placed on this tariff.	**Current**	**TOU (two period)[12]**	**CPP –F,[13] CPP –V,[14] RTP[15]**	**Current**	**Current**	**CPP-Pure**
Opt-In Tariff, i.e, optional tariff customer can choose in lieu of default tariff.	**N/A**	**Current or CPP-F**	**Current or TOU**	**CPP- Pure[16]**	**CPP-F or CPP- V**	**Current**
CASE ASSUMPTIONS						
Base Case	**1**					
Partial Deployment Cases						
Operational – Conventional Financing	**2**					
Operational – Outsourced Financing	**3***					
Demand Response		**6**	**8**	**11**	**15**	**18**
Demand Response + Reliability				**12**	**16**	
Full Deployment Cases						
Operational – Conventional Financing	**4**					
Operational – Outsourced Financing	**5***					
Demand Response		**7**	**9**	**13**	**17**	**19**
Demand Response + Reliability			**10**	**14**		

* PG&E did not perform separate cases for "outsourced" financing. See Section II.C below.

A. Description of Base; Partial Deployment; and Full Deployment Cases

The ACR directs the utilities to prepare three "cases": a "base" case; a "partial deployment" case; and a "full deployment" case.

1. Base Case or "Business As Usual"

[12] A TOU rate has different pricing at predetermined levels, during different daily time periods, every day of the year.

[13] CPP-Fixed, or CPP-F, is a rate where CPP events and prices, triggered on a day-ahead basis, are overlaid on a year-round TOU rate. CPP events are of uniform duration and limited to 15 days per year.

[14] CPP-Variable, or CPP-V, is a rate similar to CPP-F, except that CPP events can be triggered on the same day and be of variable duration. However, uniform five-hour events were assumed for this analysis.

[15] Under RTP (Real Time Pricing) electricity is priced in each hour based on market prices. It is typically not a rate suitable for any but the largest customers (over 200 kW), and was not analyzed in this filing.

[16] CPP-Pure is similar to CPP-F except it is not overlaid on a TOU rate. CPP-Pure has a flat rate in all time periods of the year except for the CPP periods on the CPP days.

The ACR describes the “base” case, or “business as usual” case, as “the expected capital and maintenance costs associated with maintaining current metering and communication systems for all customer classes, including planned upgrades to metering and billing systems for the 2006 to 2021 period.”

PG&E interprets the “base case” (case 1) as capturing the costs the utility will incur for its metering systems and related processes in the absence of AMI deployment. The base case represents the costs assumed for metering under PG&E’s current operations. PG&E has not included in its base case any future spending that might occur to secure some of the operational benefits offered by AMI. All costs for the AMI cases are incremental to the base case.

Detailed assumptions underlying the base case are found in Appendix A.

2. Partial Deployment and Full Deployment Cases

The ACR provides each utility with discretion in defining its preferred “partial deployment” case. PG&E’s partial deployment case assumes installation of AMI metering in the hottest summer locations in its service territory. It focuses on the Central Valley (so-called research climate zones “R” and “S”, see map and table in Appendix A). PG&E’s rationale for choosing this partial case is that these areas have demonstrated, in the SPP, price-responsive elasticities that are significantly higher than in other zones. Climate zones R and S are also large enough geographically to allow economies of scale and scope to be realized that would not accrue on the “pilot” scale, or in a single city deployment.

The ACR also requires a “full” deployment case under which “[i]n no event should the deployment schedule exceed five years or reach less than 90% of the utility’s customer base.”

All of PG&E’s AMI deployment cases (whether partial or full) assume 100 percent deployment of both gas as well as electric meters for customers whose electric usage is below 200 kW. Gas meters are included in PG&E’s cases since a majority of customers receive both gas and electricity from PG&E. If only electric meters were AMI-enabled, manual meter readings would need to continue for dual commodity customers. PG&E would then not accrue most of the direct utility operational benefits associated with an AMI deployment.

Detailed assumptions underlying the partial and full rollout cases are in Appendix A.

B. Description Of Three "Scenarios" Under Partial and Full Deployment Cases

The ACR requires that for the partial and full deployment cases, the utilities analyze three "scenarios": "Operational"; "Demand Response"; and "Demand Response + Reliability."

1. Operational Scenario

The Operational scenario for both partial and full rollout is described in the ACR as follows: "This scenario assumes that no new tariffs are established as a result of the . . . deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case."

PG&E's Operational scenarios are included in cases 2 and 4 of Appendix B. These cases include all costs for infrastructure necessary to read meters on an hourly basis, store usage information and interface with the billing system. The only costs excluded, compared to the demand response and demand response plus reliability scenarios, are systems programming costs for dynamic rates and customer communications costs.[17]

2. Demand Response Scenarios

The Demand Response scenarios assume "that new tariffs are established as a result of the . . . deployment of AMI, so costs and benefits that derive from the rollout of a specified set of new tariffs are included." PG&E's Demand Response scenarios are shown in cases 6, 7, 8, 9, 11, 13, 15, 17, 18, and 19 of Appendix B. The ACR provides specific guidance as to the different

[17] PG&E did not cost out a pure automated meter reading (AMR) operational case (which would not have included features to deploy dynamic rates if the CPUC chooses to implement such rates in the future).

types of tariff structures to use in each Demand Response scenario. The tariff structures assumed are described in more detail in Appendix D.

3. Demand Response + Reliability

The "Demand Response + Reliability" scenarios, for both partial and full deployment, include "the costs of any additional control and communication systems necessary to automatically reduce the load of customers who have agreed to a predetermined peak load reduction (of 10- 20%) during emergency conditions."

PG&E's Demand Response + Reliability scenarios (cases 10, 12, 14, and 16 of Appendix B) assume dynamic pricing tariffs are enabled and customers with air conditioning, who do not "opt-out" of dynamic rates, are offered direct load control technology (smart thermostats) on an "opt-in" basis. Customers opting for smart thermostats are subject to utility-controlled load reduction (via a 4 degree temperature set-back) during critical peak pricing periods.

C. Alternative Implementation and Financing Approaches: Internal vs. Outsourcing

The Ruling directs that the utilities consider outsourcing of implementation and financing in their analyses. PG&E has incorporated this directive to the extent possible. First, PG&E's meter installation analysis assumes that non-PG&E labor will perform that function.[18] However, PG&E's analysis assumes PG&E will perform operation and maintenance (O&M) of the AMI system after installation.

Second, with respect to outsourced financing, PG&E has not yet chosen a technology path or a vendor for AMI. PG&E's acquisition strategy, deployment strategy, and resulting cost information are therefore not sufficiently refined for this purpose and a single set of costs is used in this filing. PG&E's analysis of bid responses from the RFP process will enable PG&E to

[18] PG&E has assumed installation will be performed by non-PG&E union labor at "prevailing union wage rates."

assess contracting options and the cost difference between utility ownership and outsourcing – if there is any.[19]

D. Exclusion From This Preliminary Analysis Of Customers Over 200 kW

PG&E's AMI analysis excludes customers over 200 kW at this time, both from a costing standpoint and a benefits standpoint. Most customers over 200 kW already have advanced meters (many of which were funded under AB 29X). Currently there are about 800 customers over 200 kW without advanced meters. The Commission has deferred the issue of providing these customers with meters. In the Assigned Commissioner's November 24, 2003 Ruling in this docket, the Commission stated that the issue of meters for these customers was a "clean up" item that would be addressed separately.

E. Other Analysis Assumptions and Parameters

All general analysis parameters used by PG&E are listed and explained in Appendix A.

III. DISCUSSION OF KEY MARKET, REGULATORY, AND FINANCING FACTORS THAT COULD AFFECT THE ANALYSIS

PG&E's preliminary business cases are subject to market, regulatory and business environment changes that could affect the results. While assumptions regarding costs and benefits are addressed in detail in the sections that follow, certain more global assumptions regarding factors beyond PG&E's control should be noted.

A. Regulatory and Legislative Environment

The California Legislature plays an active role in shaping energy policy and future

[19] PG&E will include its proposal for financing in its application. Outsourced financing is an option PG&E will consider. However, leasing arrangements (one type of outsourced financing option) are traditionally an unattractive source of financing for PG&E due to the additional costs associated with leasing compared with conventional secured debt financing and because many of the traditional benefits of leasing are not applicable to PG&E.

legislation could significantly affect the business case. In addition, regulatory policy can likewise affect the analysis of AMI. For example, this Commission, the CEC, and the Federal Energy Regulatory Commission currently have numerous open proceedings, and may open other proceedings, that can substantially affect the costs and benefits in the business cases:

CPUC's Resource Adequacy proceeding: PG&E assumes the CPUC and the California Independent System Operator (ISO)[20] will allow PG&E to count the demand response predicted from AMI for purposes of meeting PG&E's resource adequacy requirements. The avoided cost benefits calculated in this analysis are based on the assumption that demand response programs can avoid construction of new generation facilities, such as combustion turbines, or procurement of capacity. If the demand response is not counted toward meeting PG&E's resource adequacy requirements, the cost-benefit analysis could change. Guidelines have been discussed at CPUC-sponsored resource adequacy workshops to determine the amounts of dependable demand response that can be counted in planning reserves[21] to reduce procurement costs.[22] Since there has not yet been a final Commission decision on counting rules, the inputs and assumptions used in the demand response model are inherently speculative and uncertain.

CPUC's Avoided Cost proceeding: The valuation of demand response in the avoided cost proceeding could have a material impact on the ultimate business case results in this

[20] ISO recognition of demand response as a resource that can displace procurement is critical to valuing demand response.

[21] If demand response also reduces the amount of planning reserves (currently 15% of peak demand) associated with load, the total amount of reduced capacity procurement would be 115% of dependable demand response.

[22] For example, under the revised draft decision of ALJ Wetzell, issued October 6, 2004, demand response would have a minimal seasonal (May-September) performance requirement of 48 hours. In addition, demand response programs that can be operated for only two hours per day would be capped at 0.89% of the monthly system peak (about 150MW for PG&E.)

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proceeding. The preliminary analysis presented here assumes a value of $85/ kW-year for demand response as specified in the ACR. However, PG&E believes that the avoided cost valuation of demand response is still an open question.

Future CPUC AMI proceedings: The timing of decisions in a future AMI application could affect the deployment schedule and, in turn, influence the results contained in this business case. The current business case assumes an aggressive deployment schedule; if this is delayed as part of the regulatory processes, deployment costs could increase significantly.

Implementation of Assembly Bill (AB) 1X: AB1X imposes a rate freeze on 130 percent of baseline usage for residential electric customers. Depending on how this statute is implemented by the Commission in dynamic rates, demand response from residential customers could be muted. At this time, however, PG&E has not factored AB1X restrictions in its modeling of dynamic rates for this preliminary analysis.

Other potential regulatory or legislative impacts: No specific legislative or regulatory actions are forecast to change within the business case. Nevertheless, any changes in fundamental policy items such as service reliability criteria, information requirements for customers, tax laws, etc. could significantly affect the business case.

B. Business and Financial Environment

Financial and energy markets can rapidly change and have an impact on the business cases. PG&E notes the following key assumptions that are not assumed to change:

PG&E has the same service territory and customers: The business cases do not include any assumptions about change in customer make-up due to the Community Choice Aggregation program, expanded Direct Access, municipalization efforts by other entities, or any other service territory or customer base shift (such as implementation of a core non-core model).

Continued operation of the California Independent System Operator: The business cases assume current rules for transmission and distribution planning and operation. If these change, estimates of savings from T&D deferrals could be affected.

Growth in the meter population over the next 15 years remains steady: The business cases assume electric customer growth at an average rate during the forecast horizon just below 1.5 percent per year. Changes in the economic climate (i.e., boom or recession) could alter this assumption.

Force majeure events: The business cases do not assume any contingency forecasts for significant events such as labor strikes, natural disasters, extreme weather or other force majeure events which could occur during the deployment timeline and could result in delays or altered plans.

IV. COSTS

On September 27, 2004, PG&E issued an RFP to potential vendors for an AMI system and a load control system. Supplier responses are due to PG&E on November 10, 2004. Following receipt of responses, PG&E will commence an evaluation process to narrow the field of potential vendors and start to conduct detailed due diligence of selected vendors. After evaluating the various proposals, PG&E plans to enter into negotiations in early 2005 with selected suppliers to solidify a deployment plan and determine final costs.

Accordingly, PG&E anticipates having more comprehensive and accurate estimates of costs both after the initial RFP results arrive and after vendor negotiations are complete. For now, the results shown in this filing are considered preliminary estimates. PG&E anticipates that most estimates would be updated to reflect the costs of the technology choices and all downstream actions to implement that technology. Each cost outlined in the July 21 ACR is addressed in Appendix B and PG&E's workpapers. Appendix B is confidential, and submitted pursuant to Public Utilities Code section 583. Therefore, while this section discusses cost items, PG&E intentionally avoids the provision of any cost-related numbers in this public document.

A. Methodology For Estimating Costs

For this filing, PG&E estimated incremental costs to implement AMI, i.e., those metering and systems costs above and beyond those requested in the last (2003) General Rate Case, based on both market information and internal company estimates. Market information was obtained primarily from responses to a “request for information” (RFI) the company issued on January 9, 2004. Market information is generally used in this business case analysis when available. However, market information available to PG&E did not always provide sufficient detail or cover all activities necessary for PG&E to determine the total cost of AMI. PG&E utilized its own cost estimates to fill market information gaps.

Many of the costs and benefits for the full and partial deployment cases are proportionate to the number of meters deployed (i.e., meter and network costs, installation costs, meter reading savings and demand response benefits). However, certain costs (e.g., systems costs to operate an automated system, collect and process hourly usage data for all customers and handle dynamic pricing) are largely fixed and do not vary significantly with partial or full deployment.

B. Major Cost Drivers

The major cost components of AMI deployment are as follows:

1. Metering System and Communications Network

The biggest cost component is the installed cost of the meters and meter-reading network. There are several AMI technologies capable of meeting the requirements outlined in the July 21 ACR. In selecting a combination of technologies for its preliminary analysis, PG&E considered costs and whether the technology has been deployed successfully on a commercial scale. Specific detailed costs that may be required for other types of technology or system interfaces are therefore not estimated.

PG&E stresses that these working assumptions do not imply that the technologies assumed in this preliminary business case will ultimately be chosen. They were used in the business case only because specific technologies must be assumed for the sole purpose of developing a preliminary cost estimate. The assumptions used in this filing should not prejudge what technology PG&E may ultimately recommend after reviewing the results of its RFP. PG&E's technology choice assumptions are shown in Appendix B.

The second significant factor influencing meter installation costs is the fraction of meters that require retrofitting or replacement. Based on the types and ages of PG&E's current electric meter population, a supplier estimated the percentage of existing electric meters that will be retrofitted with an AMI module and the percentage that will be replaced with new AMI meters. The business case also makes assumptions about the percentage of existing residential gas meters that will be retrofitted, and the percentage that cannot be retrofitted due to the meter's condition and will be replaced with new AMI enabled gas meters. These assumptions are shown in workpapers.

2. Information Technology (IT) Systems Costs

The other major component of costs is IT systems costs. While not as large a contributor to costs as meter costs and technology choice, these costs are nevertheless a significant cost driver. PG&E's estimates for upgrades to its billing system to handle the increased data storage and processing requirements of AMI, the programming and testing of dynamic tariffs, the interface with the AMI system and systems integration are shown in Appendix B for each case.

3. Enabling Load Control Technology Costs

For the Demand Response + Reliability cases, PG&E's business case assumed the costs of installing smart thermostats for a sub-set of customers requesting this technology. In addition to the end-point installation costs, PG&E also assumed an annual incentive payment to these customers in return for the utility having the ability to set back their thermostats during system emergencies. These technology costs, and the incentive payments, add significantly to the costs in these cases.

C. Cost Uncertainties

The cost estimates in this analysis are based on certain assumptions that could be different when AMI is rolled out. These factors create uncertainty around the costs. Even though these uncertainties can have both upward and downward pressure on costs, PG&E conservatively assumed that costs may be higher than the costs in this analysis and added a contingency of 5 percent on the cost estimates of AMI system deployment.

Examples of uncertainties that could lower costs include PG&E's RFP responses, and the possibility of accelerated tax depreciation of AMI systems under Federal law (realized by some utilities with AMI systems in other states). PG&E assumed no accelerated depreciation in this analysis.

Other significant cost uncertainties include:

Meter failure rate: Because AMI technology has not been widely deployed, and the newer technologies do not have a lengthy track record, reliable meter/module failure rates are not available. PG&E therefore used a failure rate based on preliminary meter vendor information. The assumed failure rates are shown in PG&E's workpapers.

Meter accessibility: For this analysis PG&E anticipated that, given its unique service territory, a large number of PG&E's meters will be initially inaccessible to the installers for installation purposes requiring greater costs to complete.[23] PG&E's assumptions are shown in

[23] Many of these meters can be read visually by PG&E's meter readers today, or are read by the plastic card method.

PG&E's workpapers.

Costs of communicating CPP events to customers: PG&E has assumed customers on CPP tariffs will be notified of CPP events via media announcements at minimal or no cost to PG&E. If this approach were found to be insufficient, or if the Commission requires a separate customer-specific communication method, or network, the costs could be significant.

Costs of educating customers about AMI and dynamic rates: PG&E has assumed a substantial cost for this activity as shown in Appendix B. However, if the Commission requires more extensive marketing and education efforts, this cost assumption could be too low.

V. BENEFITS

Benefits fall into three broad categories. These are direct utility operational savings; customer benefits; and demand response benefits. PG&E's analysis of these benefits is preliminary and subject to revision after responses to the RFP are analyzed, after the summer 2004 SPP data becomes available, as PG&E refines its analysis, and as the issue of demand response valuation is further addressed. The detailed analysis and quantification of these benefits for each case is provided in Appendix B.

A. Direct Utility Operational Savings

These are savings that are expected to lower utility operational costs, and hence the revenue requirement. While PG&E quantified certain operational savings, PG&E believes that these may well understate the true value of AMI for utility operations. AMI is expected to improve the efficiency of PG&E's business processes in ways that are not yet foreseeable or quantifiable. Like most new technologies, PG&E expects that uses will be found for the AMI system that will improve operations.

The savings estimates presented in this filing are preliminary and will be revised as PG&E refines its analysis. Some of these benefits depend on the capabilities of the AMI technology ultimately selected and will be revised after the RFP process is complete. The most significant operational savings are discussed below.

1. Quantifiable Direct Utility Savings

Saved Meter Reading Costs: The largest quantifiable operational savings from AMI deployment are those associated with saved meter reading costs. The AMI system will read meters on an automated basis greatly reducing the need for meter reading personnel. These savings will accrue over a period of years as the AMI system is rolled out**.** PG&E is committed to working with its labor unions to ensure that the impact of AMI on PG&E's meter readers is mitigated to the extent practicable consistent with the objectives of the AMI project.

In estimating meter reading savings for this preliminary analysis, PG&E assumed that 100 percent of meters will be read by some kind of automated technology. All field visits for malfunctioning meters will be handled as a new O&M cost. The meter reading savings estimates in this preliminary analysis are based on a full rollout and are scaled down for the partial deployment scenarios.

The total annual savings estimated by PG&E from a reduction in meter readers, management, administrative support, and associated costs, is shown in Appendix B.

Phone center savings: With AMI, PG&E expects a reduction in the number of certain types of calls from customers. The reduction stems from fewer meter misreads; better information or understanding by customers of prior usage; fewer outage-related calls due to improved information; fewer delayed bills (due to unavailability of meter reads); fewer estimated bills (due to unavailability of meter reads); and fewer meter reading complaints.

Improved billing: AMI will result in higher quality bills containing fewer estimated reads or meter reading errors thereby reducing bill processing costs and increasing customer satisfaction.

Outage management benefits: This category includes both operational savings and customer service benefits. PG&E believes that AMI has the potential to provide the data necessary to improve three functions pertaining to outage management: momentary outage detection; restoration after significant outages; and dispatch of employees in response to "no-power" calls from customers. In addition to the operational benefits that have been quantified, PG&E anticipates that the information provided by certain AMI technologies will allow PG&E to provide more rapid assessment of the power status and power restoration at each customer's premises during outages.

More efficient programming of customer rates: AMI will enable PG&E to implement customers' requested rate changes very quickly and without the costly field visits required today. For example, today a customer changing from one TOU rate schedule to another requires a field visit; this visit would be avoided with AMI because the new rate program could be enabled remotely.

2. Un-Quantifiable Utility Savings

Certain operational benefits are not quantifiable, but should be considered when evaluating AMI deployment. These include:

Reduction in Unaccounted For Energy (UFE): UFE is an energy imbalance that cannot be assigned to a responsible party. By increasing meter accuracy and timeliness of data, AMI addresses some of the causes of UFE directly. However, this benefit cannot be quantified.[24] Even if the potential reduction in UFE could be quantified, it would represent a shift in cost responsibility among customers, rather than a reduction in total costs charged to customers as a whole.

[24] During the first half of 2004, the UFE costs allocated by the ISO to PG&E exceeded $10 million.

Possible New Revenue Sources /New Products & Services: AMI will enable an array of new functional capabilities. However, it is too early to know whether any of these potential new functional capabilities can be used to provide new business products or services and if any of those new products or service offerings would be beneficial for customers, the utility, or third-parties. Therefore, while there may be new products and services, the costs or benefits of these services are not included in the present business case analysis.

B. Customer Service Benefits

PG&E believes AMI can result in a significant increase in customer satisfaction, even though this benefit is difficult to quantify or value. Customer Service benefits include directly quantified benefits, such as reduced number of calls to the utilities (see operational benefits discussion above), and indirect benefits to customers. The direct benefits accrue to customers through a reduction in a future revenue requirement. Indirect benefits, on the other hand, are a benefit to customers outside of the tariffs charged by PG&E.

PG&E expects that AMI will result in fewer estimated or inaccurate bills; will allow some flexibility in customer selection of a bill cycle date; will provide better outage information; and will provide options for customers to view their usage data in detail, perhaps via the internet.

These improvements in service will reduce the need for customers to spend time and energy in contacting PG&E to address bill accuracy, or to get a better understanding of their energy usage. This has a value to customers and to society since it frees customers to pursue other tasks. For example, a small business customer may be able to focus its attention toward meeting its own business goals rather than contacting PG&E to review the energy usage issues from a recent billing statement.

Better outage management information available to PG&E will improve the outage restoration and customer communication process. In addition, less intrusive meter reading is a value to customers who do not need to be contacted by PG&E to restrain a pet or to be available for a meter reading appointment.

Finally, customers may have an opportunity to choose from a wider range of programs or rate options. This benefit includes empowering customers with a greater ability to affect their energy bills by adjusting their own behavior. This will be a particularly important benefit during an energy shortage.

There is also a category of customer service benefits resulting in a better allocation of costs to the retail end user actually using the energy. For example, through anti-tampering technology AMI is expected to improve detection of energy theft and to ultimately reduce energy theft. Although customers might see a slight rate reduction due to reduced theft from the system, the greater benefit may accrue to society, in the form of saved enforcement resources.

C. Demand Response Benefits

Demand Response benefits accrue from system peak load reductions resulting from customer response to dynamic pricing. These benefits include the avoided capacity costs of procuring incremental electric resources during summer on-peak hours and the reduction in future costs of transmission and distribution upgrades. In addition, to the extent that customers use less electricity rather than just shifting usage from one period to another, there are benefits stemming from reduced energy procurement. PG&E's demand response benefits estimated in this filing are preliminary and subject to revision.

Demand response benefits are highly speculative based on lack of direct experience and other factors. The major variables driving demand response are:[25]

[25] It should be noted that to the extent some of the predicted demand response estimated by the model does not count towards resource adequacy under the Commission's "counting" rules being developed in the resource adequacy proceeding, AMI's avoided procurement benefits would be less than predicted.

- Peak prices under dynamic rates versus current non-AMI tariffs (i.e., the higher the prices, the greater the demand response; but higher peak prices can also lead to higher opt-out rates);
- Customer participation in dynamic pricing (i.e., opt-in or opt-out rates). These are affected by variables such as design of specific dynamic rate structures and default tariffs, and marketing;
- Energy demand elasticities, i.e., how customers respond to changes in price by rate period. The elasticities assumed in this analysis are subject to revision when summer 2004 SPP data becomes available.

To capture the variability associated with these inputs, PG&E performed an uncertainty analysis to obtain ranges of demand response.

Valuation of demand response is also a critical variable depending on two factors – "countability" and monetary value. The preliminary analysis assumes all demand response MW predicted by the CRA model will be counted as a resource for purposes of PG&E meeting CPUC-adopted resource adequacy requirements. This assumption depends on Commission implementation of rules that allow PG&E to count the predicted demand response and on ISO acceptance of the predicted demand response amounts. If demand response is not counted, it has no avoided procurement value. As to monetary value, the preliminary analysis presented here assumes a value of $85/ kW-year for demand response as specified in the ACR. However, the avoided cost valuation of demand response is still an open question.

1. Procurement Cost Reduction Due To Demand Response

a. Description of Model Methodology

PG&E's consultant, Charles River Associates (CRA), modeled the various scenarios specified in the Commission's Ruling based on specific information about PG&E's service territory, weather and customer base. CRA used its model to estimate the impact on peak demand and energy consumption by pricing period, and to derive the total estimated reduction in peak MW usage. In simple terms, the CRA methodology for each tariff option can be described as follows:

MW Impact = (a) (Average use per customer during peak period on the current rate) X
(b) (% Drop in peak period use per customer given a change in price) X
(c) (Number of customers) X
(d) (Customer participation rate)

This MW impact is summed across all rate options available in the given scenario. Items (a) and (c) are derived from PG&E's load research data, billing files, and residential appliance saturation data (for Demand Response + Reliability scenarios). Item (b) is estimated by CRA using information on the rate of price responsiveness from the SPP with PG&E-specific weather for the residential sector and literature research for the small commercial sector. Item (d) is estimated by drawing upon the market research performed during the pilot.

The MWh impacts are estimated from CRA's model using a similar approach to the one used for estimating MW impacts. The primary difference is the impacts are estimated for both the peak and off-peak periods.

Total Benefits = [(MW Impact) X (Avoided capacity cost)] +
[(MWH Impact by period) X (Avoided energy cost by period)].

The results from the model estimating reductions in peak demand and energy consumption are summarized in Appendix B for each scenario.

b. Key assumptions

Estimating the potential reduction in peak demand in the model above requires several critical inputs and assumptions. As noted before, PG&E assumes the CPUC and the ISO will allow PG&E to count the demand response predicted from AMI for purposes of meeting

PG&E's resource adequacy requirements. To the extent some of the predicted demand response does not count toward resource adequacy, the avoided capacity benefits from AMI would be less than predicted.

Rate of customer price responsiveness (elasticities): PG&E applied the rate of customer price responsiveness for the CPP–F (fixed), the CPP-V (variable), and the Time-of-Use (TOU) rate options that were estimated in the SPP for residential customers. The elasticities were modified to reflect PG&E weather conditions and the saturation rate of central air conditioning systems. Currently, these elasticities are based on Summer 2003 pilot data, but they may be updated after the Summer 2004 data is analyzed. In particular, Summer 2004 data will provide some insight into whether customer response measured in 2003 is indicative of customer response in a subsequent year and over a two- or three-day CPP event over an extended high temperature period.

PG&E included cases involving a CPP-P (pure) rate option that has flat prices (as opposed to the TOU rates in CPP-F) in all hours of the year except during CPP events. Results for this rate, while not explicitly tested for in the SPP, can be deduced from the SPP results. For residential CPP-P rates, PG&E assumed the price elasticities were the same as for the CPP-F rate on CPP days. For small commercial and industrial customers, the elasticity estimates were based on a review of the literature and were taken primarily from a pricing pilot performed by PG&E in the early 1980s. CRA derived estimates of the elasticity of substitution and daily price elasticity that were consistent with a low-end impact estimate from the PG&E pilot study.

Customer participation rates: PG&E developed a series of customer participation rates for each of the scenarios described in the July 21 ACR based on judgment and the market research carried out in the SPP by Momentum Market Intelligence. The Momentum quantitative market research provides information on customer preferences for specific rate options under either an opt-in or opt-out situation. It also provides some insight into preferences for a specific rate given different alternative rate options. The numbers are still only relative preferences and subject to a variety of interpretations. The actual participation rates assumed for each scenario are listed in Appendix D. PG&E points out, however, that actual customer participation will depend in part on the type of rates the Commission ultimately adopts, the specific prices and other characteristics of those rates, how they are marketed to customers (especially whether they are marketed on an opt-in or opt-out basis) and the number and type of alternative rates available to customers.

Value of peak capacity and energy: In this analysis, PG&E used the avoided cost figures provided by the ACR to estimate the value of demand response capacity and energy, i.e., $85/kW-yr for avoided capacity and $70/MWh for avoided energy during the peak period. PG&E used these values in its preliminary analysis since they were specified in the ACR. However, PG&E believes that the avoided cost valuation of demand response is still an open question.

Customer use of technology (smart thermostats): PG&E assumed that the Reliability scenario requires a utility-dispatchable technology at the customer facility similar to the “smart thermostat” program tested in the SPP. While other technologies on other customer appliances can be deployed in a utility reliability program, the SPP approach and results allowed PG&E to estimate a reasonable reliability response option for this filing.

PG&E assumed for the Demand Response + Reliability scenarios that the smart thermostat technology is offered only to the subset of customers with central air conditioning. PG&E also assumed the customer would not pay for the technology.

The saturation of air-conditioning by climate zone was estimated from PG&E customer responses to the CEC's Statewide Residential Appliance Saturation Survey. As a result, for each scenario where a reliability feature is modeled, PG&E estimated which fraction of customers with air-conditioning would choose both the CPP rate and the smart thermostat. The specific participation rates are listed in Attachment D.

Current share of peak and off-peak usage by type of customer: This information comes from PG&E's load research files and from billing records. For each rate class, CRA developed an estimate of how much electricity is consumed by the typical customer during a summer month on weekdays and on holidays and weekends. CRA also divided monthly energy used on weekdays into the energy that is used during the peak and off-peak periods. These values are calculated for each of four climate zones.

Time Varying Rate/Pricing Structures: The specific prices upon which benefit estimates are based are seasonally revenue neutral vis a vis the current rate offered to each customer segment. The rates are also similar to those tested in the SPP. For the purposes of this filing, PG&E developed estimated demand response benefits for 12 of the scenarios described in the July 21 ACR, together with the two additional scenarios selected by PG&E. This benefit calculation involved modeling the effects of four different basic rate options[26] to estimate resulting demand response benefits: (1) Time of Use (TOU) rates, (2) Critical Peak Pricing (CPP) rates without enabling technology, (3) CPP rates with enabling technology, and (4) existing rate structures. The benefits associated with each rate option were determined by comparing the new prices in each rate period with the prices that exist under the current tariff. The small commercial analysis was performed separately for customers on each of four existing

[26] RTP rates were not analyzed for the preliminary business case since customers over 200 kW have been excluded.

rates, A1 (small commercial with a seasonal rate differential), A6 (small commercial with a time-of-use rate), A10 (medium commercial with a demand-based, non-time-of-use rate) and E19V (voluntary rate schedule with demand and time-of-use rate elements).[27] These combinations produce a total of 14 different demand response scenarios. PG&E used relatively generic rate design assumptions for each of the basic rate design options, because it would be premature to develop full-scale proposed tariffs at this stage of the analysis.

PG&E notes that there will be strong inter-relationships between specific rate design assumptions and the other analysis parameters assumed for each scenario. For example higher TOU ratios or CPP prices would be likely to produce higher per-participant demand response benefits, but would most likely also result in higher opt-out rates and, consequently, potentially a lower level of overall demand response. Similarly, there will be some definite relationship between overall participation rates and how revenue responsibility is ultimately divided between the default, opt-in, and opt-out tariffs that might be established for each customer class. For example, if new rate "premiums" were to be attached to service under the existing non-TOU rate schedules (while TOU or CPP rates were established as default tariffs), this would presumably result in lower opt-out rates. The generic rate design, opt-in, opt-out, and demand response assumptions, described in Appendix D, reflect PG&E's best current judgment of what can reasonably be assumed for the purposes of the present analysis.

c. Addressing Uncertainty in the Key Assumptions

To capture uncertainty inherent in the above assumptions, CRA performed a Monte Carlo analysis on the range of customer price elasticities. A list of all elasticities used is in Appendix D. A second analysis placed an upper and lower range for each customer participation rate. The

[27] While customers greater than 200 kW take service off schedules A10 and E19V, the SPP and the resulting analysis was limited to customers less than 200 kW.

participation rates and ranges differ for each scenario with different rate option combinations and different default rate assumptions. Finally, the results were combined to obtain lower and upper limits on MW impacts, that is, the low-end of the range of estimates based on the distribution of price elasticities was combined with the low-end of the range of estimates based on variation in participation rates and vice versa for the high-end estimate. The ranges obtained by this uncertainty analysis are reflected in Appendix B. No uncertainty analysis was performed on the value of capacity.

2. System Reliability Benefits

PG&E performed no separate or additional valuation of reliability beyond that captured by the $85/kW-yr figure specified by the Commission. However, the demand response plus reliability scenarios (i.e., demand response rates plus utility triggered automatic thermostat set back) produce additional dependable load reductions and thus have higher total benefits. PG&E valued these additional MW at $85/kW-year but attributed no separate system reliability benefit.

However, PG&E believes that AMI can be a powerful tool in the event of a future energy crisis. The ability to determine and price on-peak usage will enable a variety of programs by the Commission and the utilities to mitigate high prices and outages such as were experienced in summer 2000. PG&E believes this possible use of AMI as a policy tool has significant potential value.

3. Avoided/Deferred Transmission and Distribution (T&D) Additions/Upgrades

For certain scenarios, the CRA model described above estimates significant reductions in peak loads. If AMI reduces peak loads as predicted, a temporary “over-capacity” condition will occur on portions of the T&D system. PG&E estimates that this condition could last for approximately 3-4 years (as measured at the system level) depending on the deployment strategy (both in terms of timing and location). While the temporary "over-capacity" condition will not be uniform across each transmission and distribution planning area, the demand reduction estimates for some scenarios are significant enough to conclude that current T&D capacity expenditure forecasts could be reduced by some amount to account for the reduced demand from customer response to dynamic pricing. After a period of time, peak demand levels will "flatten-out" and the temporary "surplus capacity" generated by the reduced demand will be "consumed" by annual load growth to the point where T&D capacity expenditure levels will begin to increase again in order to meet increasing demands. PG&E estimates potential T&D deferral savings for each case and lists the values in Appendix B.

If AMI and dynamic pricing is implemented, PG&E planning engineers will continue to annually assess capacity requirements to ensure that forecasted load reductions match actual reductions. PG&E will then adjust capacity expansion plans as necessary depending on actual peak demand change.

VI. SUMMARY OF RESULTS

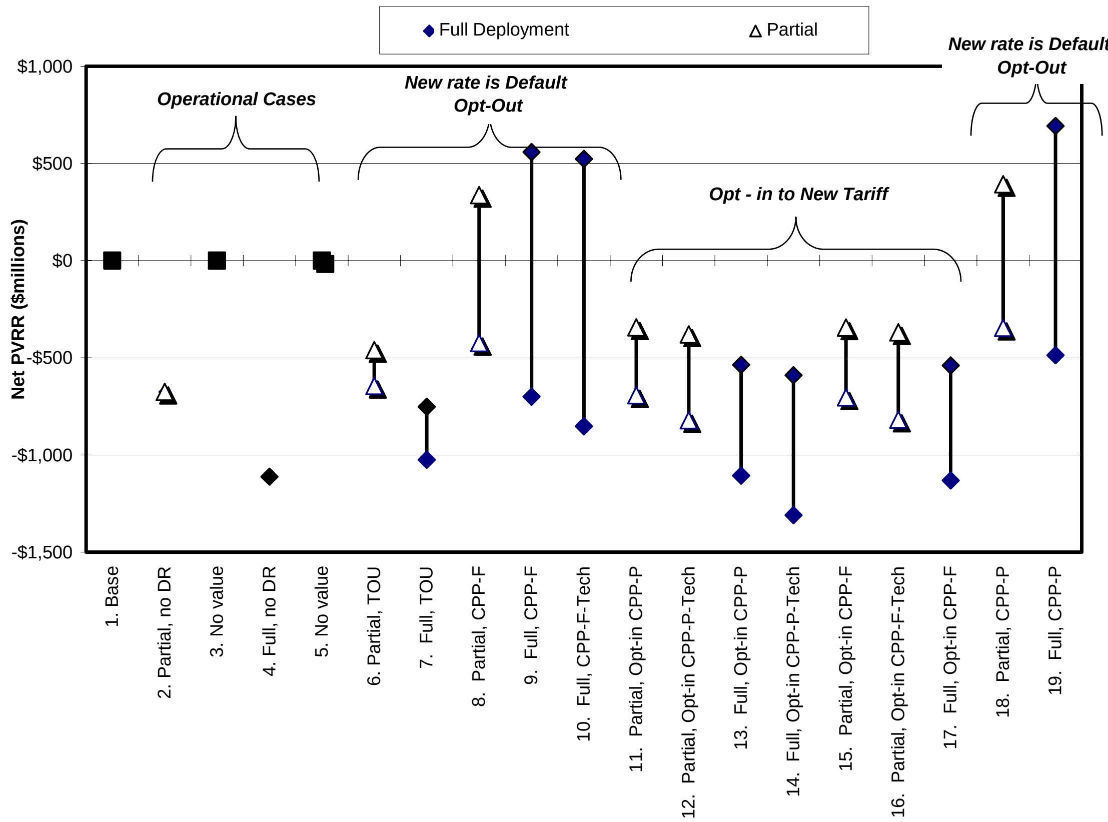
A detailed description of the results of all business case analyses performed by PG&E is attached in Appendix B. The results of PG&E's preliminary analysis of 17 of the 19 cases[28] are summarized below in both graphical and tabular form. The figure shows the range of results according to their Net Present Value (NPV). A positive result indicates that NPV benefits are greater than NPV costs. A negative result shows that costs exceed benefits. The ranges shown reflect the uncertainly analysis conducted on participation rates and elasticities. In all scenarios, demand response benefits are valued at $85/kW-year. The costs represent PG&E's tax-adjusted

[28] The two outsourced scenarios are not included, as PG&E has not performed separate analyses for "outsourced" financing.

revenue requirements.[29] The results are grouped into opt-out and opt-in categories.

In the opt-out cases, the default rate (i.e., the rate the customer is placed on initially) can be either TOU or CPP. Within the second category customers are allowed to opt-in to a CPP rate (with and without Technology) or a CPP-Pure rate (with and without Technology).

Preliminary Range of AMI Revenue Requirement NPV



The following shows these results in tabular form, mapped to the business case numbers used by PG&E:

[29] This comparison is similar to the so-called "Utility Cost" test. The April 14, 2004 Staff Report on a Business Case Analysis Framework states: "Three different perspectives needed to be considered in the analysis - utility, customer, and societal." PG&E believes it has complied with this direction by analyzing all benefits listed in the ACR, including utility, customer, and demand response benefits. All quantifiable benefits have been included in PG&E's cost/benefit test. However, PG&E has not presented a "Total Resource Cost" test or a "Ratepayer Impact" test in this preliminary analysis.

SCENARIO / CASE	Opt-out Default Tariffs (i.e., tariff customer is placed on initially)	Opt-in Tariff (i.e., tariff customer may select)	PV Revenue Requirement Result (Millions)[30]
1 (Base without AMI)	Current	NA	$0
2 (Partial Deployment, Operational Savings)	Current	NA	-$676
3 (Partial Deployment, Operational Savings, outsourced financing)	Current	NA	NA
4 (Full Deployment, Operational Savings)	Current	NA	-$1,111
5 (Full Deployment, Operational Savings, outsourced financing)	Current	NA	NA
6 (Partial Deployment, Operational plus Demand Response)	Time of Use	Current or TOU	-$645 to -$461
7 (Full Deployment, Operational plus Demand Response)	Time of Use	Current or CPP-F	-$1,025 to -$752
8 (Partial Deployment, Operational plus Demand Response)	CPP-F residential CPP-V small commercial	Current or TOU	-$424 to +$337
9 (Full Deployment, Operational plus Demand Response)	CPP-F residential CPP-V small commercial	Current or TOU	-$700 to +$559
10 (Full Deployment, Operational + Demand Response + Technology)	CPP-F residential CPP-V small commercial	Current or TOU	-$853 to +$523
11 (Partial Deployment Operational plus Demand Response)	Current	CPP-Pure	-$693 to -$343
12 (Partial Deployment, Operational + Demand Response + Technology)	Current	CPP-Pure	-$821 to -$379
13 (Full Deployment, Operational plus Demand Response)	Current	CPP-Pure	-$1,106 to -$536
14 (Full Deployment, Operational + Demand Response + Technology)	Current	CPP-Pure	-$1,310 to -$590

[30] A positive result indicates that NPV benefits are greater than NPV costs. A negative result shows that costs exceed benefits.

SCENARIO / CASE	Opt-out Default Tariffs (i.e., tariff customer is placed on initially)	Opt-in Tariff (i.e., tariff customer may select)	PV Revenue Requirement Result (Millions)[31]
15 (Partial Deployment, Operational plus Demand Response)	Current	CPP-F residential CPP-V small commercial	-$704 to -$345
16 (Partial Deployment, Operational + Demand Response + Technology)	Current	CPP-F residential CPP-V small commercial	-$819 to -$369
17 (Full Deployment, Operational plus Demand Response)	Current	CPP-F residential CPP-V small commercial	-$1,131 to -$539
18 (Partial Deployment Operational plus Demand Response)	CPP-Pure	Current	-$346 to +$393
19 (Full Deployment, Operational plus Demand Response)	CPP-Pure	Current	-$487 to +$693

Based on this preliminary analysis, five AMI deployment scenarios have potential outcomes in a positive range, with projected benefits exceeding program costs over part of the range covered by the uncertainty analysis. These results lead PG&E to the following preliminary conclusions:

- AMI appears cost–effective if customers are placed by default on CPP tariffs and a high percentage of customers remain on the CPP tariff.
- AMI is unlikely to produce sufficient demand response to be cost effective if customers are allowed to opt-in to CPP tariffs. The preliminary analysis shows an insufficient number of customers are likely to opt-in.
- TOU rates, even on an opt-out basis, appear not to be cost effective. PG&E tested a TOU rate with a 2:1 peak-to-off peak ratio. It is possible that a different TOU

[31] A positive result indicates that NPV benefits are greater than NPV costs. A negative result shows that costs exceed benefits.

rate with a higher peak price would produce greater demand response. However, it would produce this response both when needed, and when not actually required, unlike a CPP rate that provides demand response when required.

- In cases with substantial demand response, full deployment maximizes the benefits over a partial deployment. This is primarily because the fixed costs of IT systems are spread over more meters and the system continues to accrue more demand response.
- Adding smart thermostat technology to the AMI system appears to add more cost than benefit.

PG&E is not recommending, however, that any scenario be dismissed out of hand simply because of relatively low demand response benefits since these results are based on preliminary analysis subject to refinement and change. In addition, by its nature, all the benefits of a new technology like AMI cannot be fully quantified in advance. AMI, even if not cost-effective under the analysis framework presented here, may nevertheless be desirable when the Commission considers the following:

- AMI can be a powerful tool for mitigating the impact of a future energy crisis.
- AMI can provide increased customer satisfaction with utility services.
- AMI can enable new programs and options for customers and provide the Commission with new regulatory tools for demand response, and other rate structures
- AMI, like any new technology, may transform the utility’s operations in ways that are not foreseeable today.
- AMI may be more cost effective and versatile than other demand side options and

may be therefore more worthy of being funded and implemented.

For all these reasons, PG&E believes it is premature to draw any hard and fast conclusions regarding AMI based on this preliminary analysis.

VII. NEXT STEPS

PG&E continues to explore the best AMI infrastructure tools to encourage demand response, to capture future operational efficiencies, and to position its business to offer streamlined customer service moving forward. The July 21 ACR directed the utilities to file an application proposing a deployment strategy for no action, partial deployment or full deployment of their preferred cases for AMI.[32] Through its RFP, PG&E is moving forward to gain the detailed cost support required for that application and PG&E is striving to maintain a fast pace for this effort; however, the cost support information will not be available in time to file a final application by December 15, 2004.

PG&E intends to work with the Assigned Commissioner, the ALJ, and key stakeholders to develop an application schedule to enable an AMI project to be implemented consistent with all pertinent regulatory and business criteria. Such a schedule must balance the timing of the RFP and contracting process, the time necessary for the Commission to convene a hearing and to review an application, and the lead times, cash flow, and cost recovery requirements of a major capital project. PG&E believes a realistic schedule can be developed which meets all these requirements. PG&E intends to file a motion in this docket prior to the current December 15, 2004 application-filing deadline proposing a schedule.

[32] PG&E would seek cost recovery for AMI implementation costs. PG&E is a combined gas and electric utility, and assumes that approval for deployment of AMI will cover both gas and electric meters. For PG&E, this means that AMI implementation costs would need to be allocated to its electric and gas expense and capital plant, and ultimately recovered through future electric and gas distribution rates.

Respectfully Submitted,

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Dated: October 15, 2004

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APPENDIX A

General Assumptions

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APPENDIX A

General Assumptions

General Assumptions for Business Cases

PG&E incorporated the following assumptions into its preliminary business case analyses.

CPUC Directed Assumptions (ACR 7/21/200-4, pages 13-14)

1. The analysis period is 2006 to 2021. All costs and benefits are stated as a net present value of revenue requirements over a 16-year period beginning in 2006, the first year of meter deployment.

2. Benefits and costs are calculated relative to the base case. All costs and benefits are incremental to the base case.

3. Costs and benefits are presented as 2004 present value dollars, the annualized nominal values are included in workpapers.

4. PG&E performed a combination of literature review, visits to utilities with AMR/AMI systems, and use of internal estimates to ensure that reasonable methods of estimating costs and benefits were used in developing the cases. In the spring of 2004, PG&E conducted a Request For Information to better define costs of AMI. PG&E also obtained data through informal vendor solicitations. These costs, coupled with internal cost estimates, form the basis of this preliminary analysis.

5. Potential costs and benefits that cannot be easily quantified or for which no dollar value can be derived because of uncertainty or lack of data are reflected in the analysis by including a qualitative assessment of that value. PG&E lists non-quantifiable items in Appendix C and discusses certain of those items in the text of this filing.

6. The net present value of the business cases uses a weighted average cost of capital rate of 7.4%, which equals the utility cost of capital. The demand response modeling analysis used 7.7%.

7. The demand response savings estimates are based on the weighted average of savings with a range of elasticities representing weather variation. The elasticity estimation model developed in the Statewide Pricing Pilot (SPP) used weather variables developed from historic PG&E temperature data. For purposes of this parameter, average weather was defined as 1 in 2 year weather and hot weather as a 1 in 10 year weather condition. For PG&E, there was only a two-degree difference in the two types of years and the resulting elasticity estimates were well within the larger range of elasticities used by PG&E for the Monte Carlo simulations. As a result, only the average weather condition was used to determine the base elasticity. The elasticities are further described in Appendix D.

8. PG&E used an avoided peak demand cost of $85/kW-yr.

9. PG&E used an energy cost of $63/MWh except where, as suggested by the ACR, $70/MWh was during the peak period on CPP days, which adjusts for transmission and distribution congestion.

Analysis Parameters To Be Defined By PG&E (ACR 7/21/2004, pages 13-14)

In addition to the analysis parameters defined above, the Commission directed the utilities to define the assumptions used for the following parameters in the benefit cost analysis:

1. Electric data is measured hourly (except where kw demand is needed for billing, in which case data is collected every 15 minutes) and gas data is measured daily.

2. Electric data is retrieved daily; gas data is retrieved monthly.

3. PG&E modeled two-way electric meter functionality including the ability to perform on-demand reads. In addition, the system could be capable of service initialization and turn-off, and reliability technology control capability. Gas meter functionality is based on monthly drive-by technology using radio frequency-based equipment. The meter failure rates used in this analysis are shown in PG&E's workpapers.

4. Customers will have access to their usage data through secure internet access. Customers will have access to their detailed collection of peak, off-peak and critical peak pricing period usage for up to 13 months. Customers may also call into the PG&E service center to discuss their usage data with Customer Care Representatives who will have the ability to access the customers' prior days usage electronically.

5. The customer notification approach when Critical Peak Price (CPP) tariffs are triggered is accomplished using traditional mass media channels, similar to Spare the Air Day bulletins.

6. The prices and conditions for tariff structures (current tariffs, TOU, CPP-F, CPP-V, and CPP-Pure)[1] used to model potential benefits are summarized in Appendix D.

7. The cases use the expected high and low range of avoided megawatt values to determine avoided transmission and distribution costs. They vary for each case and the values are shown in Appendix B.

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[1] RTP tariffs were not analyzed since PG&E's business case currently excludes customers over 200 kW.

8. The price elasticity assumptions are listed in Appendix D.

9. The methods used to simulate customer price responsive demand for the peak period usage reduction are based on the elasticities derived from the SPP. The prices and weather assumptions are provided in Appendix D.

10. The methods used to project customer choices of different tariffs and the resulting share of customer participation in each rate is described in Appendix D. Different assumptions were used for different cases; for values, see detailed tables in Appendix D.

11. Estimate the costs to ensure that customer information systems (CIS) are compatible with collected data. PG&E estimated the costs necessary to upgrade the existing CIS systems rather than replace or outsource it. The upgrade includes the following:

    a. Building a data warehouse to collect and store interval consumption data from various AMI technologies.
    b. Modifying the current asset management systems to handle increased daily meter exchanges.
    c. Creating a platform in the operational scenarios which allows for systems to be upgraded in the future to provide all of the business requirements driven by implementation of dynamic rates.
    d. For other scenarios, expanding the current CIS infrastructure and modifying the CIS application to process and bill 4.9 million electric customers on a default TOU/CPP rate monthly.
    e. Building interfaces/linkages between the new AMI system to several linked systems such as PG&E's Outage Information System for power outage and system restoration reporting.
    f. Maintaining the current business continuity / disaster recovery levels for the upgraded systems that exist for CIS today.

<u>Other PG&E Assumptions</u>

1. Benefits are generally scaled as new AMI meters are deployed and the AMI system becomes operational.

2. The PG&E revenue requirement is presented as the present value of net cash flows through 2021, adjusted for corporate taxes. In addition, a terminal period benefit is included for the remaining useful life of the meters beyond the study period.

3. Revenue requirements are based on expected system costs, less expected benefits achieved relative to expected base case expenditures.

4. The geographic area is assumed to be the entire PG&E territory for the full deployment case, and the research climate zones R&S for the partial case, as shown on the map in Appendix A, page 7. Also following the map is a table showing PG&E's research climate zones and corresponding baseline territories.

5. PG&E's rollout schedule for Electric and Gas meters:

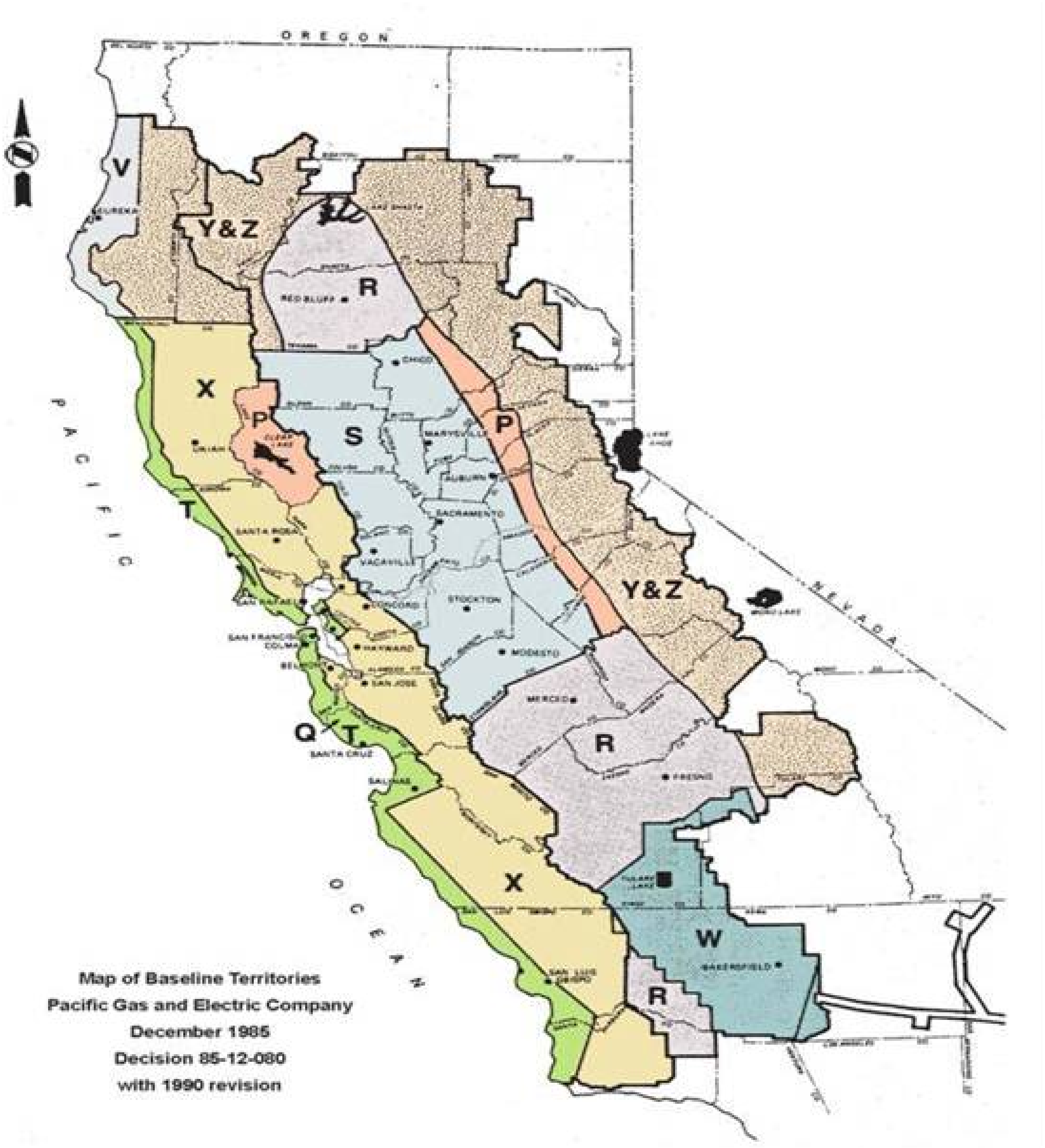
All cases assume 100% applicability to both electric and gas meters (electric below 200kW). Areas which have only gas meters are included.

Rollout Timeline Total Gas & Electric Meters	Partial Deployment Case	Full Deployment Case
2006	992,578	992,578
2007	2,339,244	3,194,297
2008	357,209	3,412,349
2009	0	1,668,941
2010	0	35,983
Totals	3,689,031	9,304,148

6. Meter retrofit versus replacement assumptions are shown in PG&E's work-papers. Meter accessibility assumptions are also shown in PG&E's workpapers.

7. PG&E's meter and network installation is assumed to be outsourced at prevailing union wage rates. However, PG&E's analysis assumes PG&E personnel will perform operation and maintenance (O&M) of the AMI system after installation.

PG&E BASELINE TERRITORIES



PG&E Climate Zone Table

Climate Zone Description	Statewide Pricing Project Zone Number	Research Zone	PG&E Baseline Territories
Coastal	**1**	**T**	**T, V, Q**
Hill	**2**	**X**	**X**
Valley	**3**	**S**	**S, P**
Desert/Mountain	**4**	**R**	**R,W,Y,Z**

APPENDIX B

Case Results
Cases B1-B19

Confidential –
Submitted pursuant to PU Code 583

UNREDACTED

TABLE OF CONTENTS

Appendix B
Case Results
Cases B1-B19

Confidential –
Submitted pursuant to PU Code Section 583

UNREDACTED

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(continued)

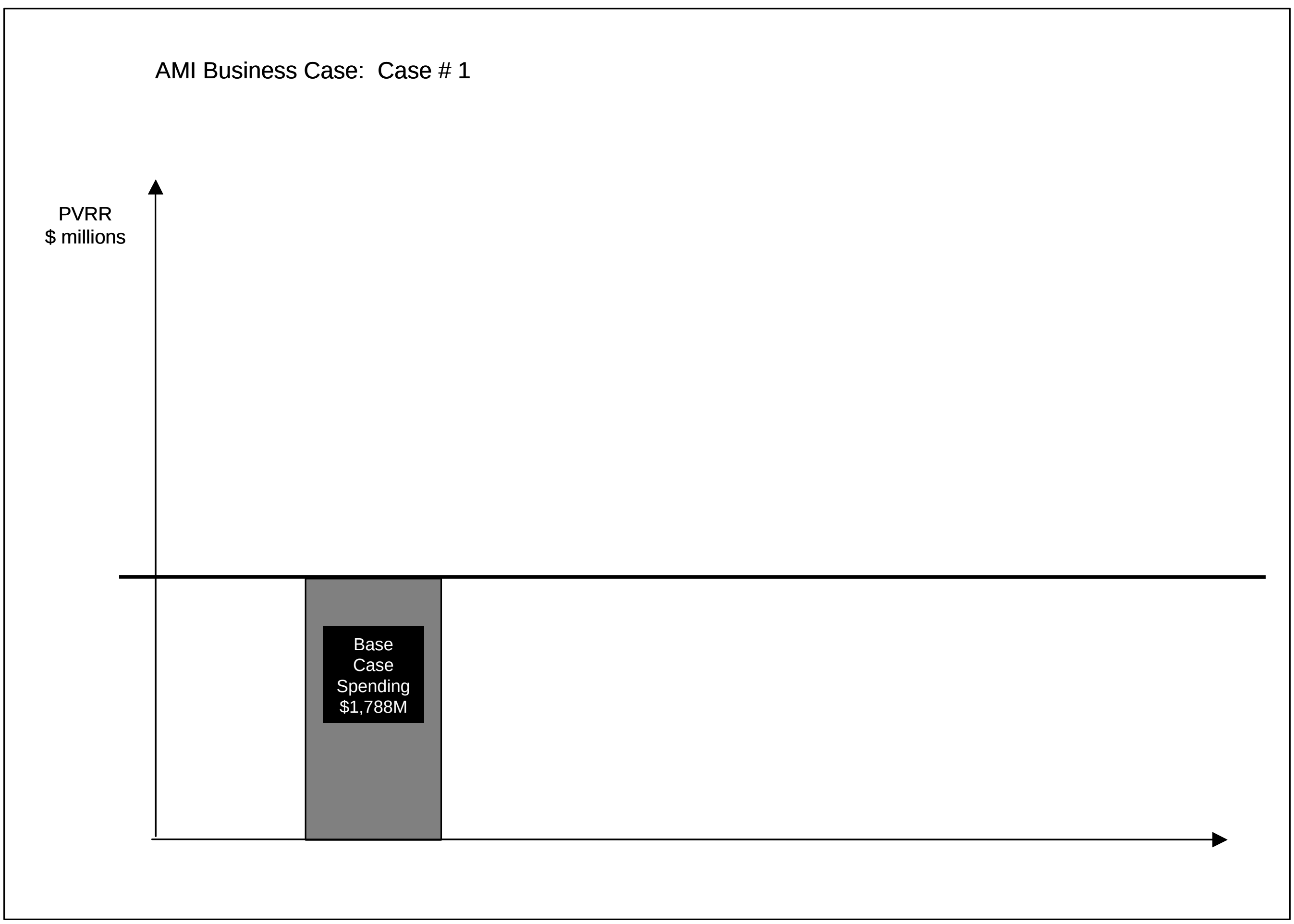
Appendix B
Case Results
Cases B1-B19

Confidential –
Submitted pursuant to PU Code Section 583

UNREDACTED

AMI Business Case #1	Assumptions	Rate Used
Deployment	N/A	N/A
Deployment start & timeframe	N/A	N/A
Reliability enabling technology	N/A	Residential or small commercial
Demand Response	Not Enabled	
Tariff structure - Default Tariff - - Optional Tariff choices	 Current None	 Current Tariff

Case Summary and observations	
Total CIS implementation cost	N/A
Meter reading benefits saved	N/A
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	N/A
Megawatt offload - by 2007 - by 2011	 N/A N/A
Transmission & distribution benefits	N/A



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$0	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$0	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$0	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$0	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$0	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$0	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$0	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$0**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$0	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$0	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$0	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$0	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$0**	

		Total - Cost Components (Deployment & O&M)	**$0**	

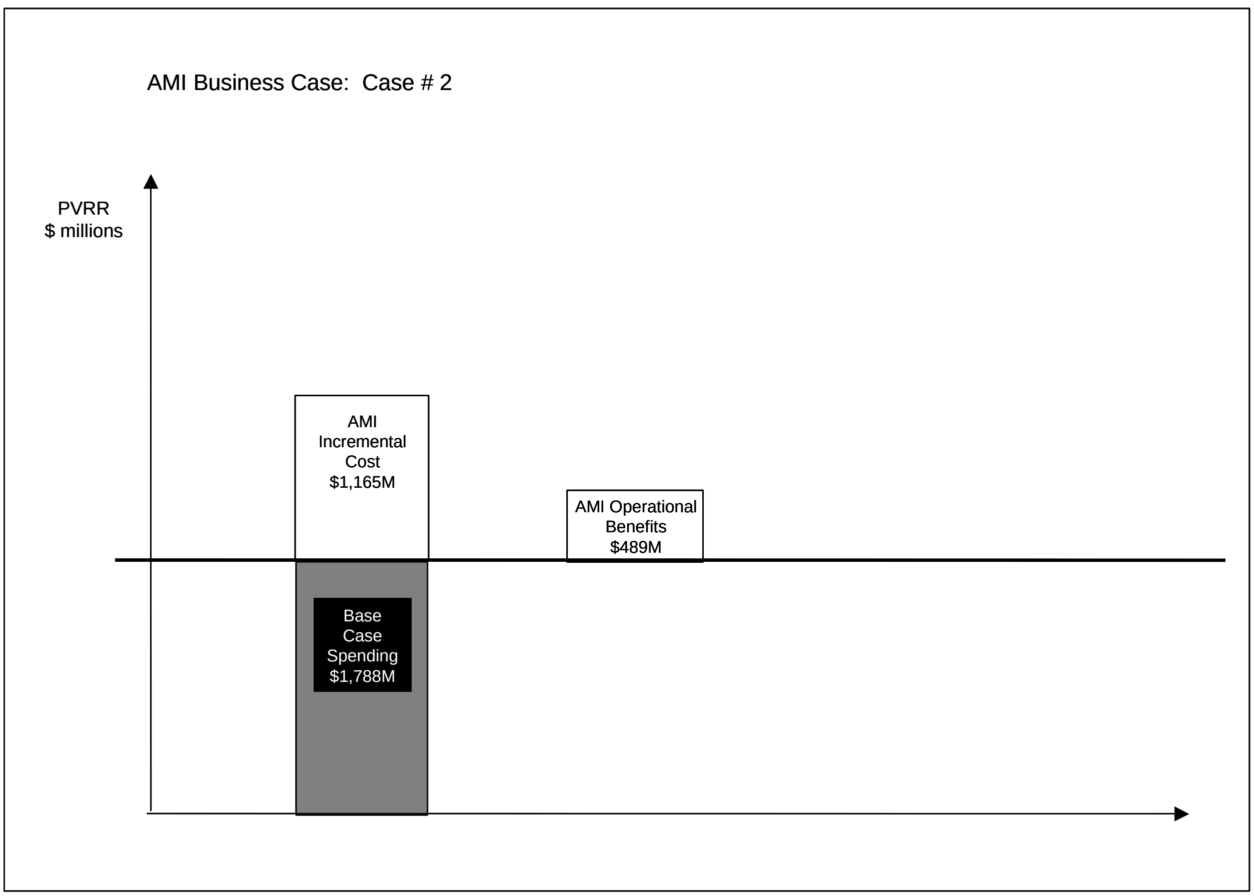
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	$0	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	$0	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	$0	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	$0	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	$0	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	$0	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	$0	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	$0	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	$0	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	$0	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions	**$0 to $0**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**$0 to $0**	
Operations	MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)	$0	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	$0	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	$0	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/web based interval & power-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	$0	
Operations	XB-1	Existing Meter Tax write-off	$0	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	$0	See Appendix C, Note 36
		Total - Benefits (before demand response)	**$0**	
		Demand Response - Minimum value	**-**	
		Demand Response - Maximum value	**-**	
	Total - System Cost		**$0**	
	AMI Operational Gap		**$0**	

AMI Business Case #2	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	N/A	Residential or small commercial
Demand Response	Not Enabled	
Tariff structure - Default Tariff - Optional Tariff choices	 Current None	 Current Tariff

Case Summary and observations	
Total CIS implementation cost	$127.7 million
Meter reading benefits saved	$361.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	N/A
Megawatt offload - by 2007 - by 2011	 N/A N/A
Transmission & distribution benefits	N/A



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$177	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$857**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$9	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$308**	

Total - Cost Components (Deployment & O&M)	**$1,165**

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**$0 to $0**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**$0 to $0**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($22)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($15)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($0)	
Operations	XB-1	Existing Meter Tax w rite-off	($4)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($56)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($489)**	
		Demand Response - Minimum value	**-**	
		Demand Response - Maximum value	**-**	
	Total - System Cost		**$1,165**	
	AMI Operational Gap		**$676**	

AMI Business Case #3	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	N/A	Residential or small commercial
Demand Response	Not Enabled	
Tariff structure - Default Tariff - Optional Tariff choices	 Current N/A	 Current Tariff N/A

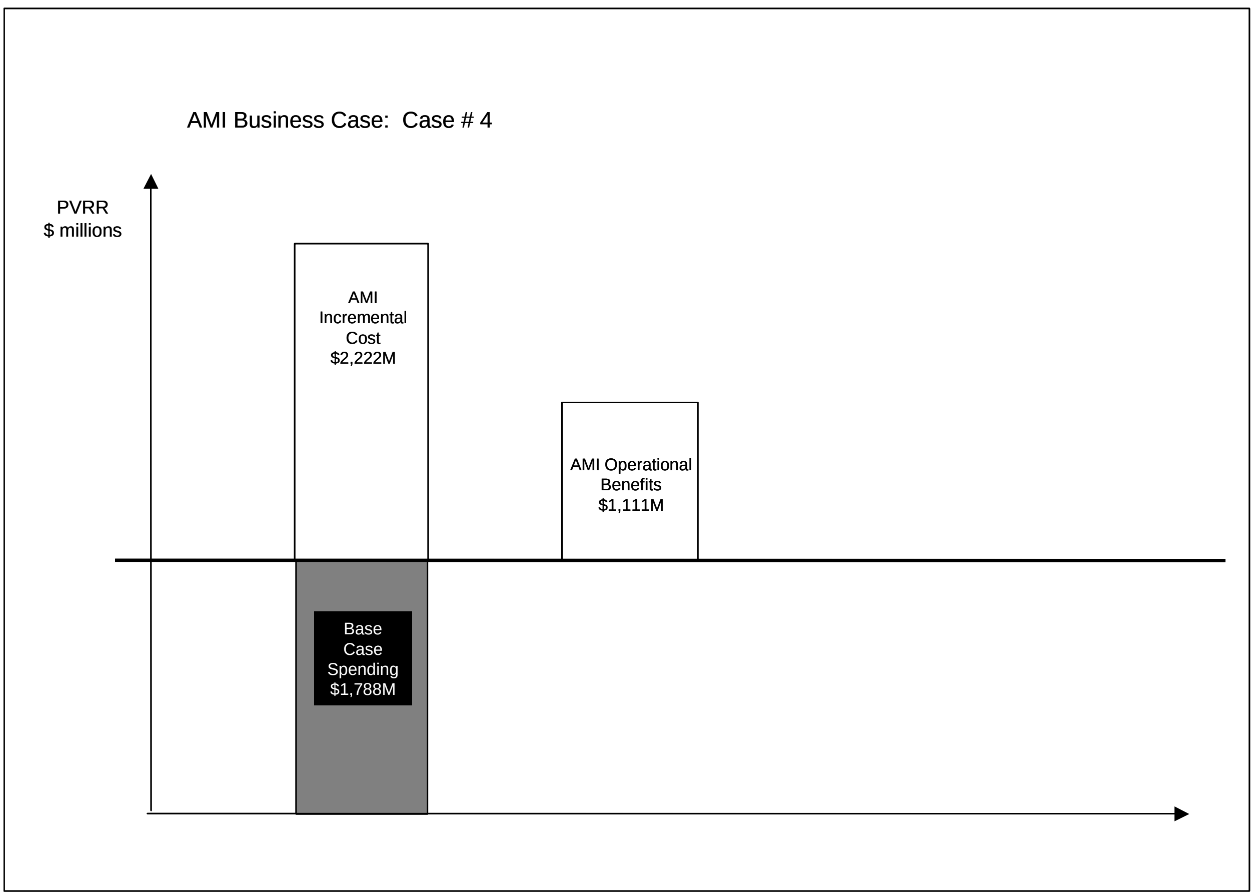
Case Summary and observations	
Total CIS implementation cost	N/A
Meter reading benefits saved	N/A
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	N/A
Megawatt offload - by 2007 - by 2011	 N/A N/A
Transmission & distribution benefits	N/A

AMI Business Case: Case # 3

Partial Deployment Case with Outsourced Financing not considered at this time. See Document section II. C.

AMI Business Case #4	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	N/A	Residential or small commercial
Demand Response	Not Enabled	
Tariff structure - Default Tariff - Optional Tariff choices	 Current None	 Current Tariff

Case Summary and observations	
Total CIS implementation cost	$149.5 million
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	N/A
Megawatt offload - by 2007 - by 2011	 N/A N/A
Transmission & distribution benefits	N/A



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$226	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,782**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$182	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$0	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$15	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$440**	
		Total - Cost Components (Deployment & O&M)	**$2,222**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**$0 to $0**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**$0 to $0**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($179)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,111)**	
		Demand Response - Minimum value	**-**	
		Demand Response - Maximum value	**-**	
	Total - System Cost		**$2,222**	
	AMI Operational Gap		**$1,111**	

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AMI Business Case #5	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	N/A	Residential or small commercial
Demand Response	Not Enabled	
Tariff structure - Default Tariff - Optional Tariff choices	 Current N/A	 Current Tariff N/A

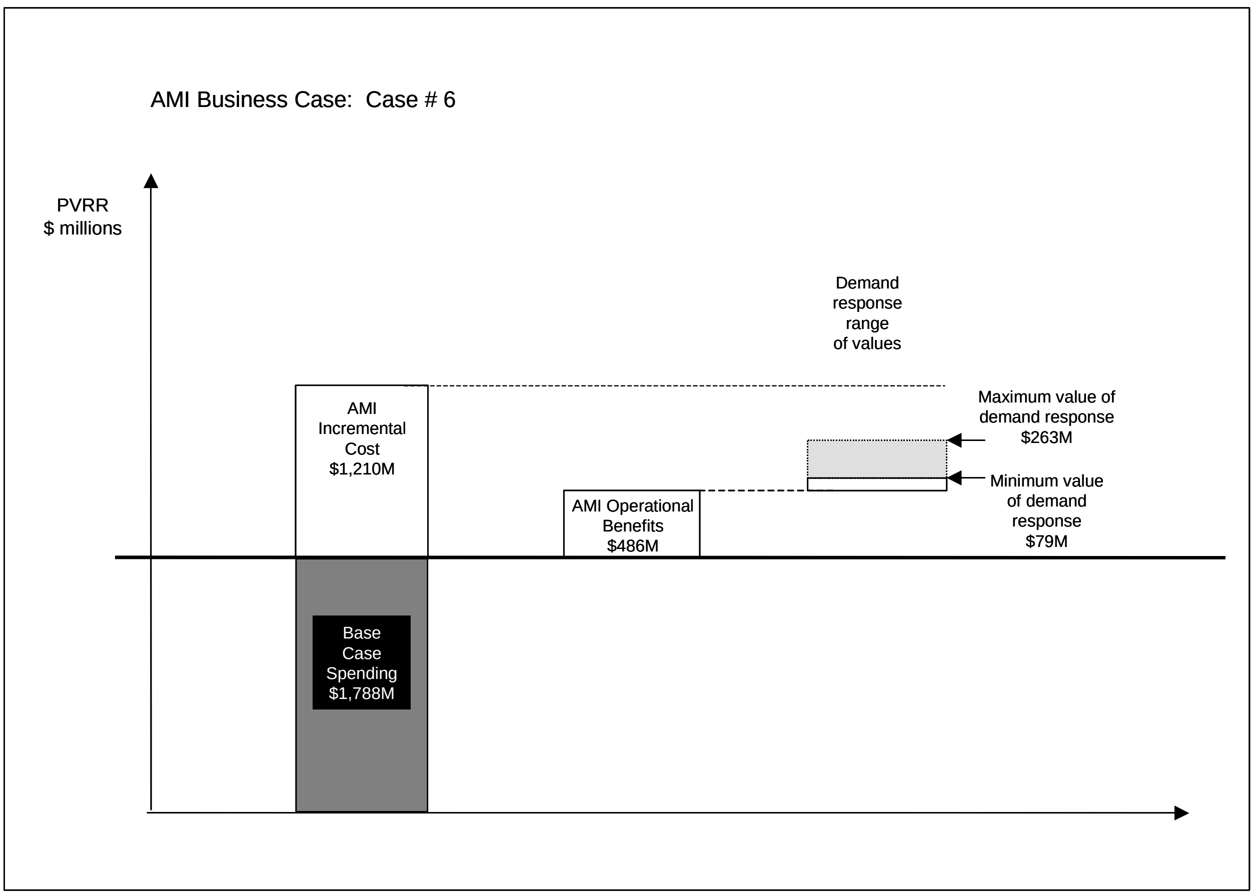
Case Summary and observations	
Total CIS implementation cost	N/A
Meter reading benefits saved	N/A
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	N/A
Megawatt offload - by 2007 - by 2011	 N/A N/A
Transmission & distribution benefits	N/A

AMI Business Case: Case # 5

Full Deployment Case with Outsourced Financing not considered at this time. See Document section II. C.

AMI Business Case #6	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Not Used	Residential or small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 TOU (two-period) Current or CPP – F	 2 / 1 peak / off-peak ratio for rates on non CPP days Current Tariff or $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$361.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$79 M to $263 M PVRR
Megawatt offload - by 2007 - by 2011	 50 MW to 160 MW 76 MW to 247 MW
Transmission & distribution benefits	$15 M to $47 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$874**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$184	
Operations	I-10	Contract administration and database management of public network connections	$6	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$8	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$1	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$18	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$336**	

		Total - Cost Components (Deployment & O&M)	**$1,210**	

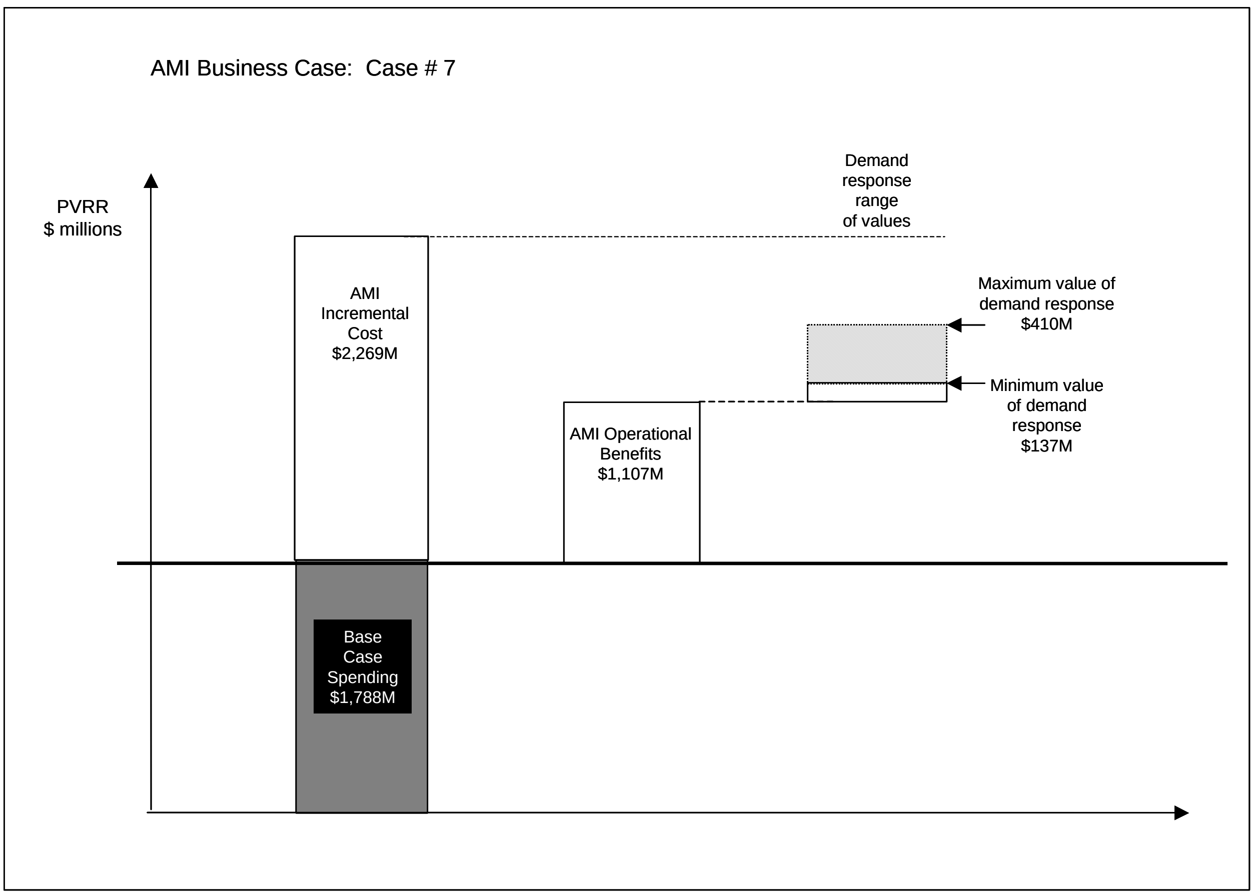
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions	**-$64 to -$216**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$15 to -$47**	
Operations	MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($22)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($15)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/web based interval & power-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($0)	
Operations	XB-1	Existing Meter Tax write-off	($4)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($53)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($486)**	
		Demand Response - Minimum value	**(79)**	
		Demand Response - Maximum value	**(263)**	
	Total - System Cost		**$1,210**	
	AMI Operational Gap		**$724**	

AMI Business Case #7	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Not Used	Residential or small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 TOU (two-period) Current or CPP – F	 2 / 1 peak / off-peak ratio for rates on non CPP days Current Tariff or $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$137 M to $410 M PVRR
Megawatt offload - by 2007 - by 2011	 58 MW to 172 MW 133 MW to 391 MW
Transmission & distribution benefits	$23 M to $68 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$243	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,799**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$2	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$26	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$470**	
		Total - Cost Components (Deployment & O&M)	**$2,269**	

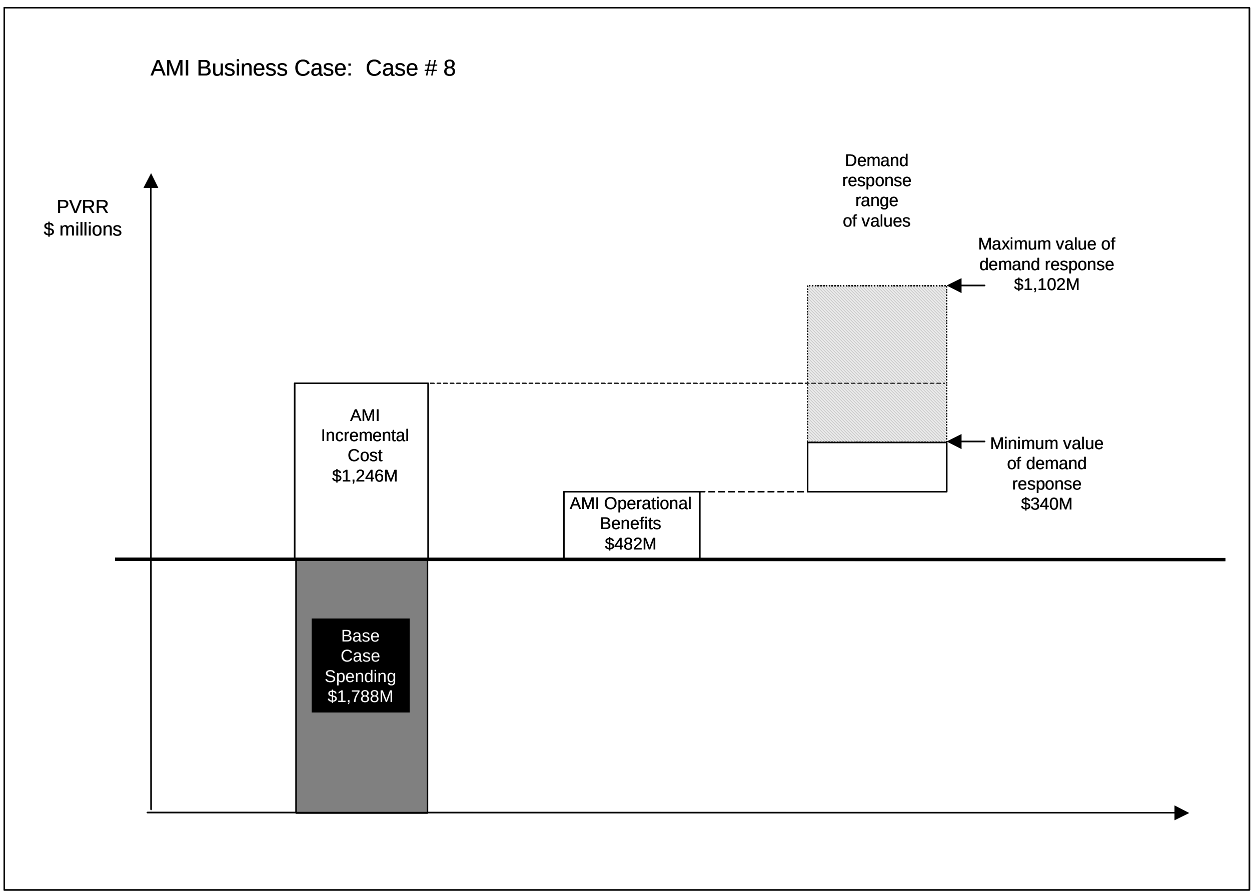
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$114 to -$342**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$23 to -$68**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($175)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,107)**	
		Demand Response - Minimum value	**(137)**	
		Demand Response - Maximum value	**(410)**	
	Total - System Cost		**$2,269**	
	AMI Operational Gap		**$1,162**	

AMI Business Case #8	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Not Used	Residential; used for small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 CPP – F, V, RTP Current or TOU	 $0.75 per kWh on Critical Peak Days 15 CPP days per year Current Tariff or 2 / 1 peak / off-peak ratio for rates on non CPP days

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$316.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$340 M to $1,102 M PVRR
Megawatt offload - by 2007 - by 2011	 213 MW to 674 MW 326 MW to 1,030 MW
Transmission & distribution benefits	$62 M to $163 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$17	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$891**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$184	
Operations	I-10	Contract administration and database management of public network connections	$6	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$8	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$4	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$11	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers with enabling technology	$23	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$355**	

Total - Cost Components (Deployment & O&M)	**$1,246**

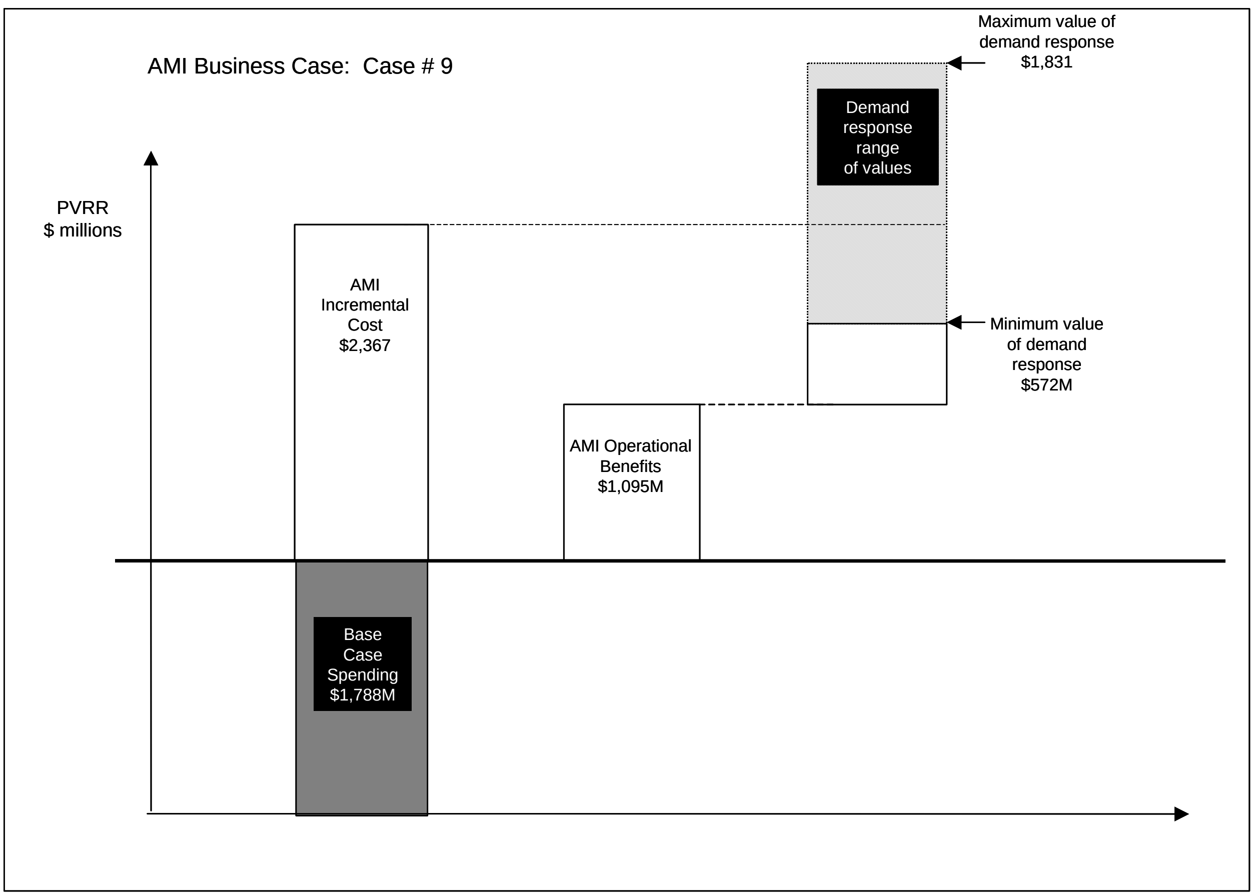
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and lower need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$278 to -$939**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$62 to -$163**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($22)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($15)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($0)	
Operations	XB-1	Existing Meter Tax w rite-off	($4)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($49)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($482)**	
		Demand Response - Minimum value	**(340)**	
		Demand Response - Maximum value	**(1,102)**	
	Total - System Cost		**$1,246**	
	AMI Operational Gap		**$764**	

AMI Business Case #9	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Not Used	
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 CPP – F, V, RTP Current or TOU	 $0.75 per kWh on Critical Peak Days 15 CPP days per year Current Tariff or 2 / 1 peak / off-peak ratio for rates on non CPP days

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$572 M to $1,831 M PVRR
Megawatt offload - by 2007 - by 2011	 245 MW to 709 MW 558 MW to 1,736 MW
Transmission & distribution benefits	$97 M to $272 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$42	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,842**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$9	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$19	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$55	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$525**	

Total - Cost Components (Deployment & O&M)	**$2,367**

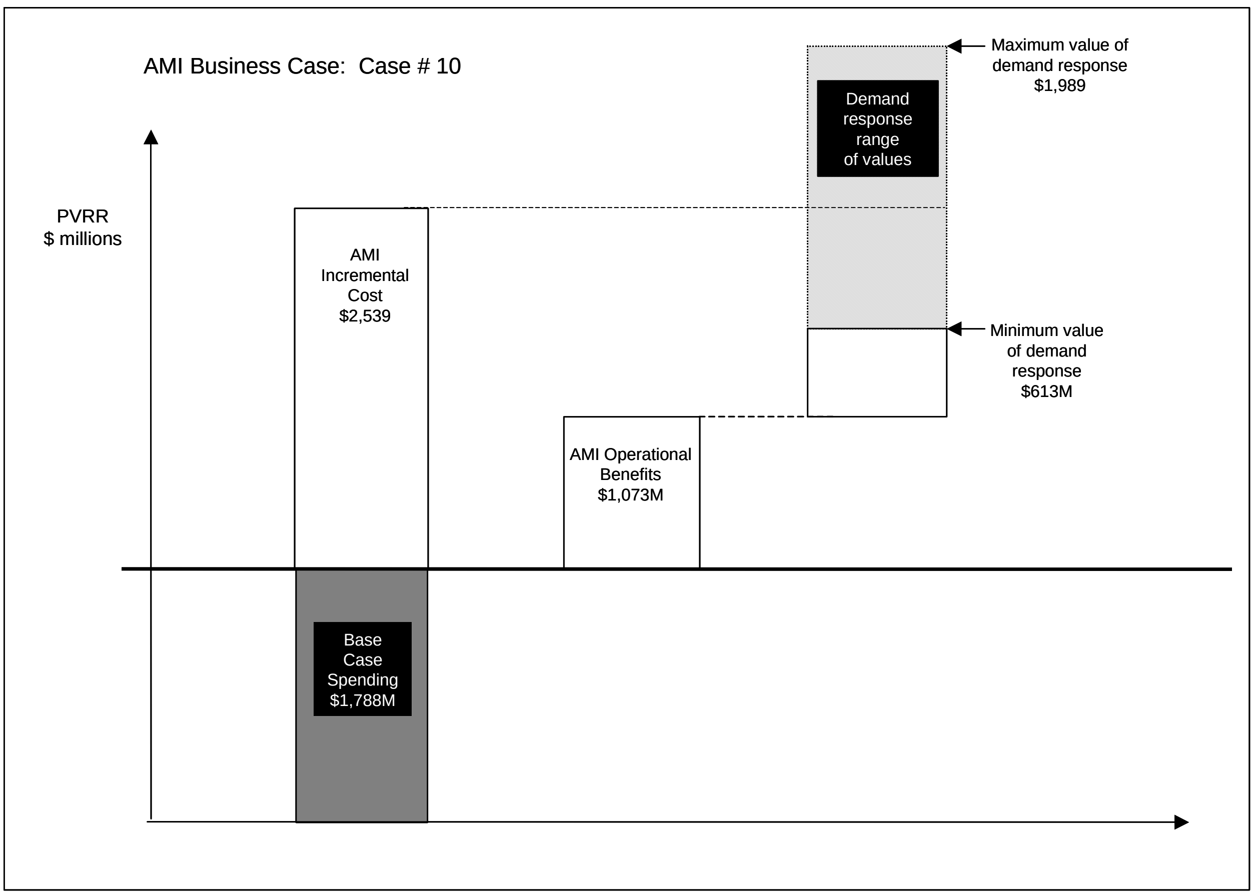
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$475 to -$1,558**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$97 to -$272**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($163)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,095)**	
		Demand Response - Minimum value	**(572)**	
		Demand Response - Maximum value	**(1,831)**	
	Total - System Cost		**$2,367**	
	AMI Operational Gap		**$1,272**	

AMI Business Case #10	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Used	Residential and small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 CPP – F, V, RTP Current or TOU	 $0.75 per kWh on Critical Peak Days 15 CPP days per year Current Tariff or 2 / 1 peak / off-peak ratio for rates on non CPP days

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$613 M to $1,989 M PVRR
Megawatt offload - by 2007 - by 2011	 269 MW to 797 MW 596 MW to 1,891 MW
Transmission & distribution benefits	$104 M to $294 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$243	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$116	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,916**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$9	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$19	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$153	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$623**	
		Total - Cost Components (Deployment & O&M)	**$2,539**	

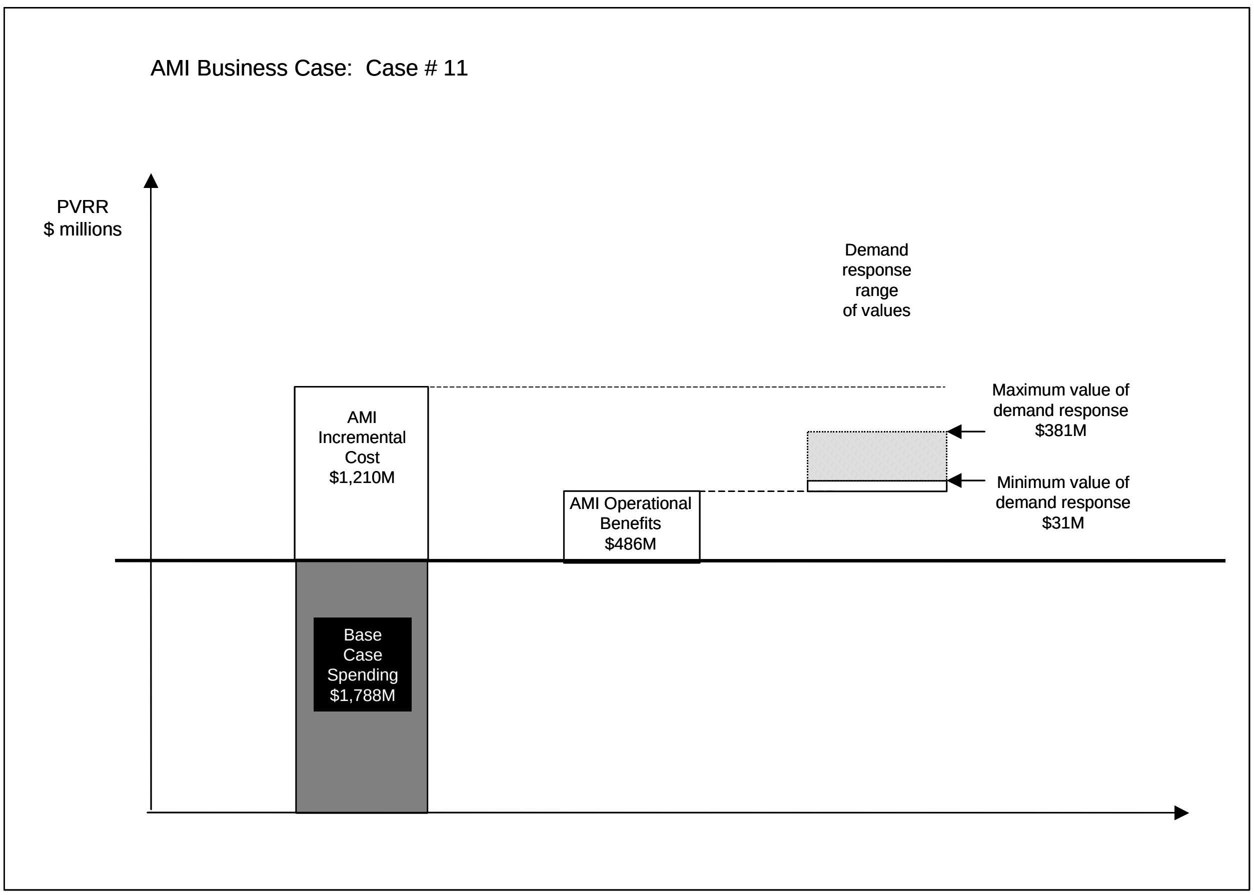
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$509 to -$1,695**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$104 to -$294**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($140)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,073)**	
		Demand Response - Minimum value	**(613)**	
		Demand Response - Maximum value	**(1,989)**	
	Total - System Cost		**$2,539**	
	AMI Operational Gap		**$1,466**	

AMI Business Case #11	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Not Used	Residential or small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – P	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$361.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$31 M to $381 M PVRR
Megawatt offload - by 2007 - by 2011	 19 MW to 224 MW 29 MW to 342 MW
Transmission & distribution benefits	$6 M to $64 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

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PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$874**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$184	
Operations	I-10	Contract administration and database management of public network connections	$6	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$8	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$1	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$18	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$336**	

Total - Cost Components (Deployment & O&M)	**$1,210**

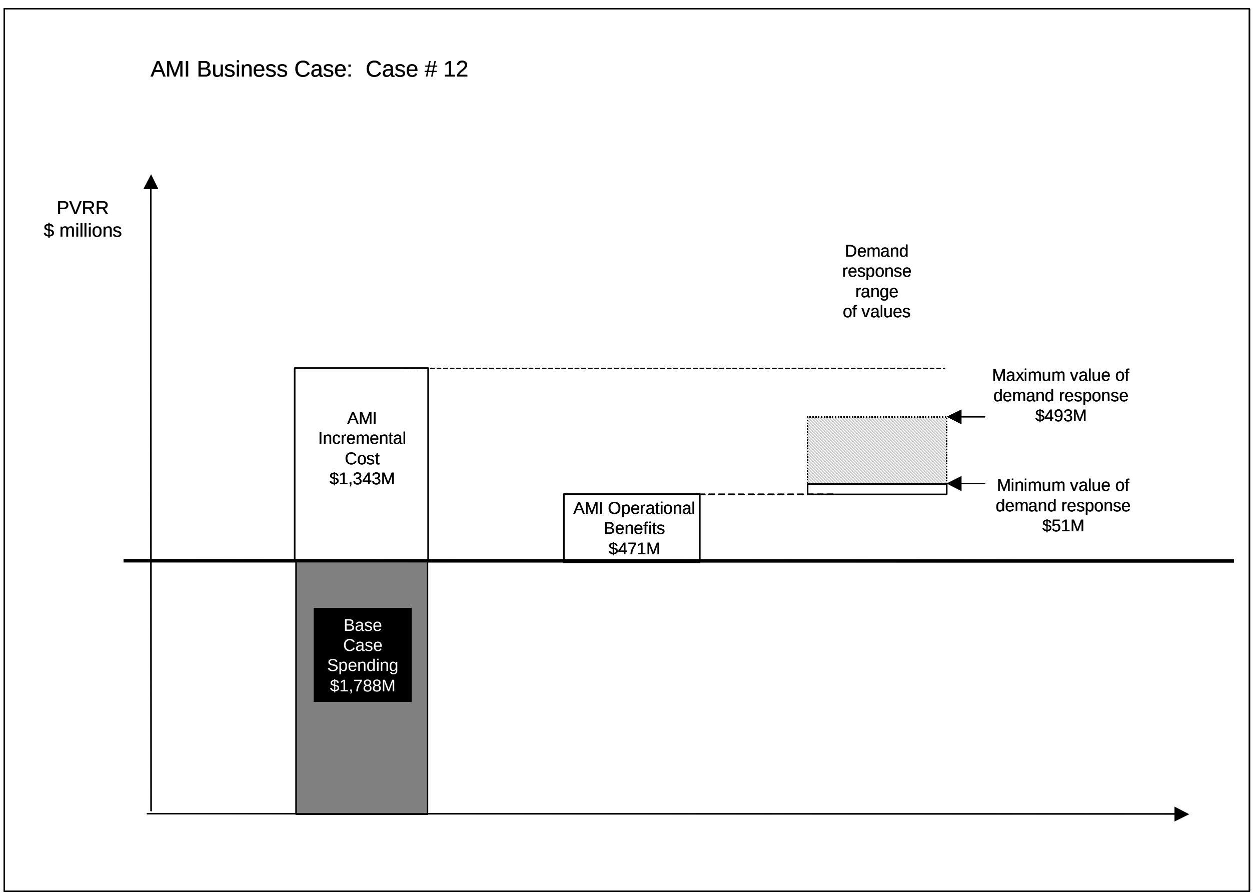
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$26 to -$317**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$6 to -$64**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($22)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($15)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($0)	
Operations	XB-1	Existing Meter Tax w rite-off	($4)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($53)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($486)**	
		Demand Response - Minimum value	**(31)**	
		Demand Response - Maximum value	**(381)**	
	Total - System Cost		**$1,210**	
	AMI Operational Gap		**$724**	

AMI Business Case #12	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Used	Residential and small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – P	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$361.5 M after-tax NPV
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$51 M to $493 M PVRR
Megawatt offload - by 2007 - by 2011	 31 MW to 294 MW 47 MW to 450 MW
Transmission & distribution benefits	$9 M to $80 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$57	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$932**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$184	
Operations	I-10	Contract administration and database management of public network connections	$6	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$8	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$1	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$18	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$76	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$412**	

Total - Cost Components (Deployment & O&M)	**$1,343**

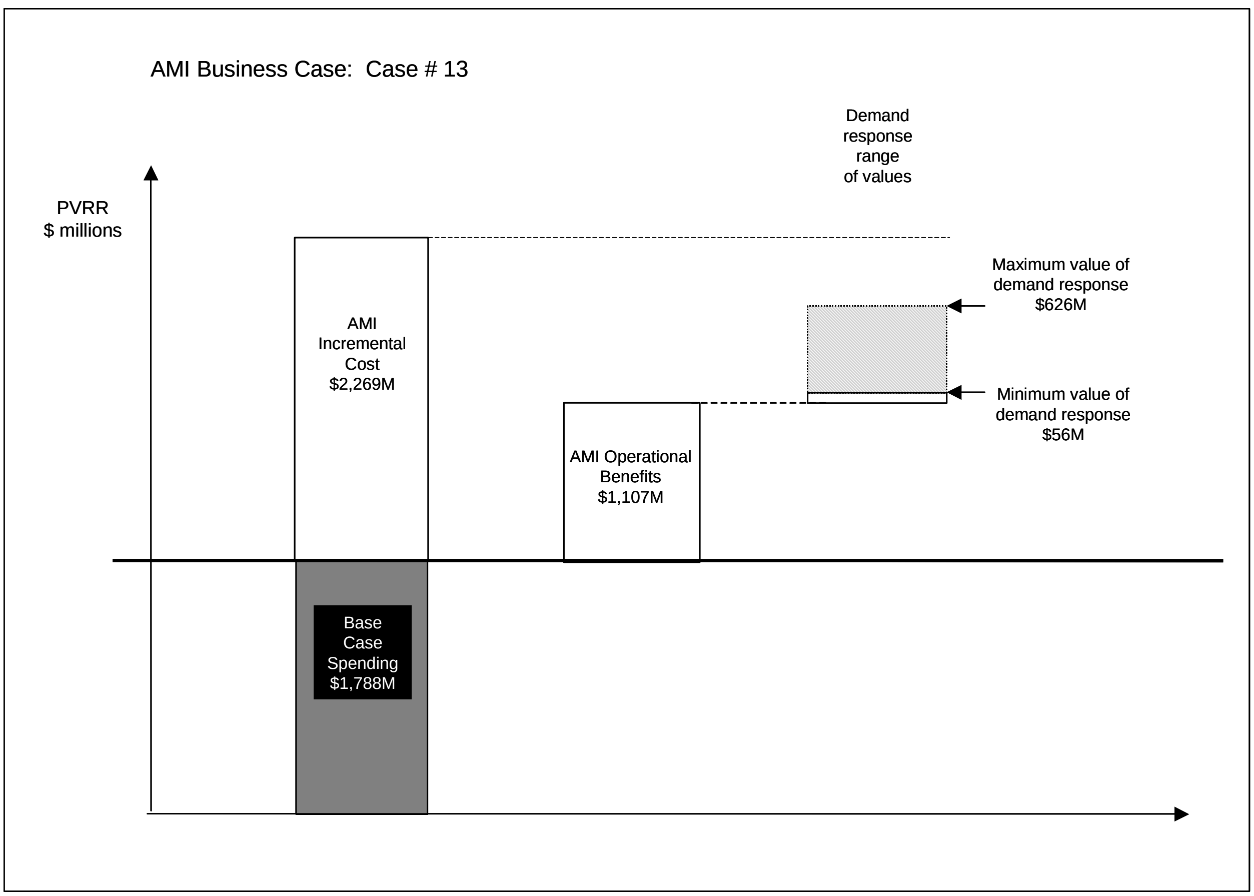
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$42 to -$413**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$9 to -$80**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($22)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($15)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($0)	
Operations	XB-1	Existing Meter Tax w rite-off	($4)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($38)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($471)**	
		Demand Response - Minimum value	**(51)**	
		Demand Response - Maximum value	**(493)**	
	Total - System Cost		**$1,343**	
	AMI Operational Gap		**$872**	

AMI Business Case #13	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Not Used	Residential or small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – P	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$56 M to $626 M PVRR
Megawatt offload - by 2007 - by 2011	 22 MW to 233 MW 54 MW to 581 MW
Transmission & distribution benefits	$9 M to $99 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$243	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,799**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$2	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$26	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$470**	

Total - Cost Components (Deployment & O&M)	**$2,269**

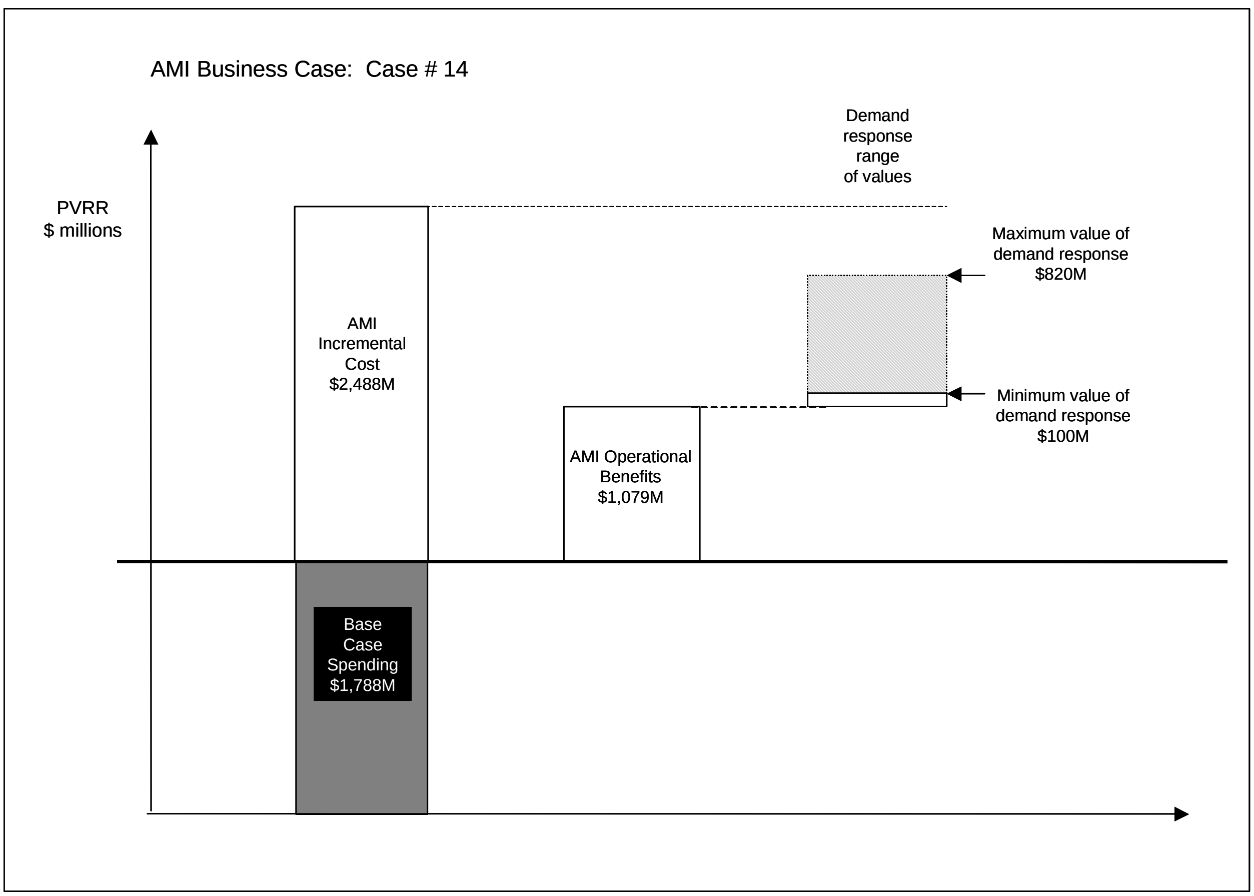
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$47 to -$527**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$9 to -$99**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($175)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,107)**	
		Demand Response - Minimum value	**(56)**	
		Demand Response - Maximum value	**(626)**	
	Total - System Cost		**$2,269**	
	AMI Operational Gap		**$1,162**	

AMI Business Case #14	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Used	Residential and small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – P	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$100 M to $820 M PVRR
Megawatt offload - by 2007 - by 2011	 39 MW to 331 MW 95 MW to 762 MW
Transmission & distribution benefits	$16 M to $132 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$243	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$95	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,894**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$2	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$26	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w/ regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers with enabling technology	$124	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$594**	

Total - Cost Components (Deployment & O&M)	**$2,488**

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and lower need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

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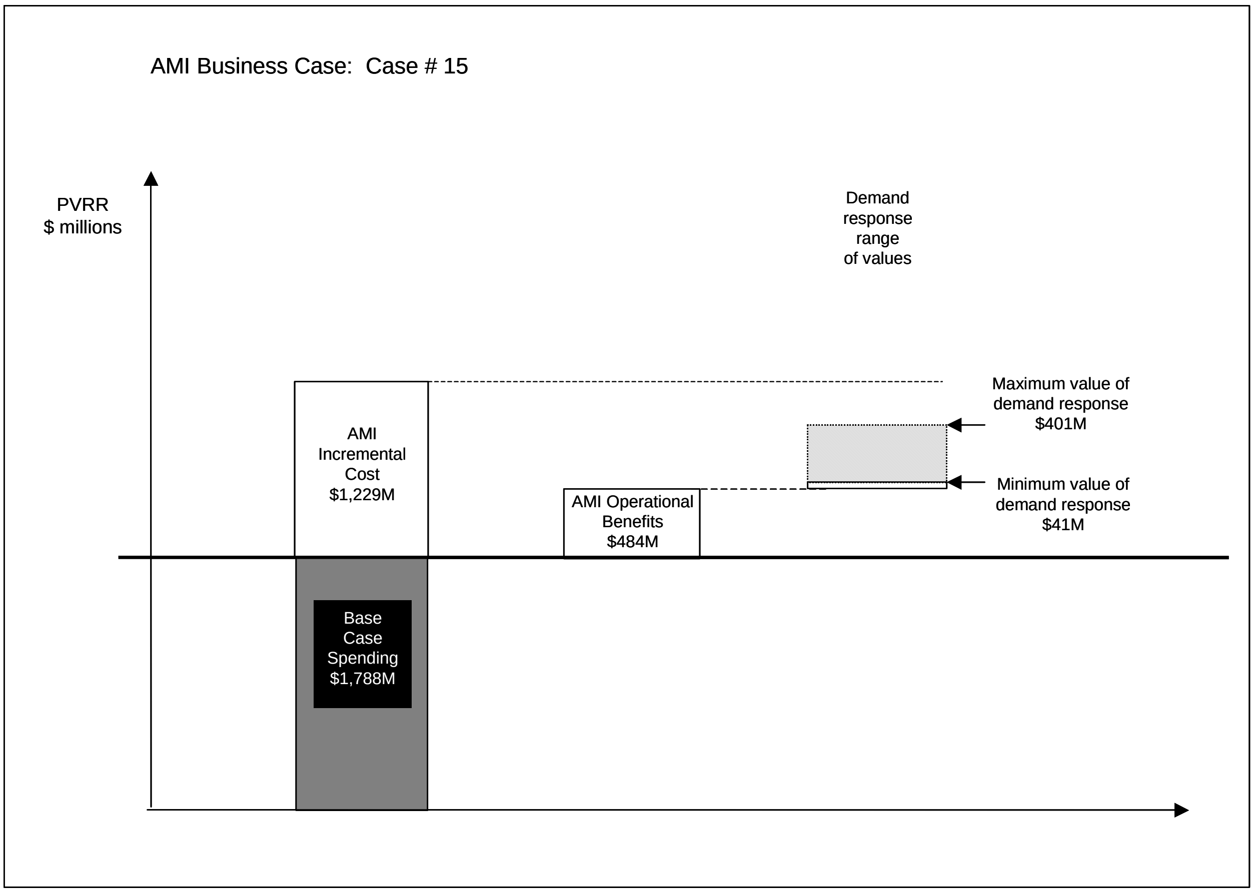
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$84 to -$688**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$16 to -$132**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($147)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,079)**	
		Demand Response - Minimum value	**(100)**	
		Demand Response - Maximum value	**(820)**	
	Total - System Cost		**$2,488**	
	AMI Operational Gap		**$1,410**	

AMI Business Case #15	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Not Used	Residential; used for small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – F, V	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$361.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$41 M to $401 M PVRR
Megawatt offload - by 2007 - by 2011	 25 MW to 237 MW 38 MW to 363 MW
Transmission & distribution benefits	$7 M to $67 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$8	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$883**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$184	
Operations	I-10	Contract administration and database management of public network connections	$6	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$8	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$1	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$18	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w/ regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers with enabling technology	$11	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$347**	

Total - Cost Components (Deployment & O&M)	**$1,229**

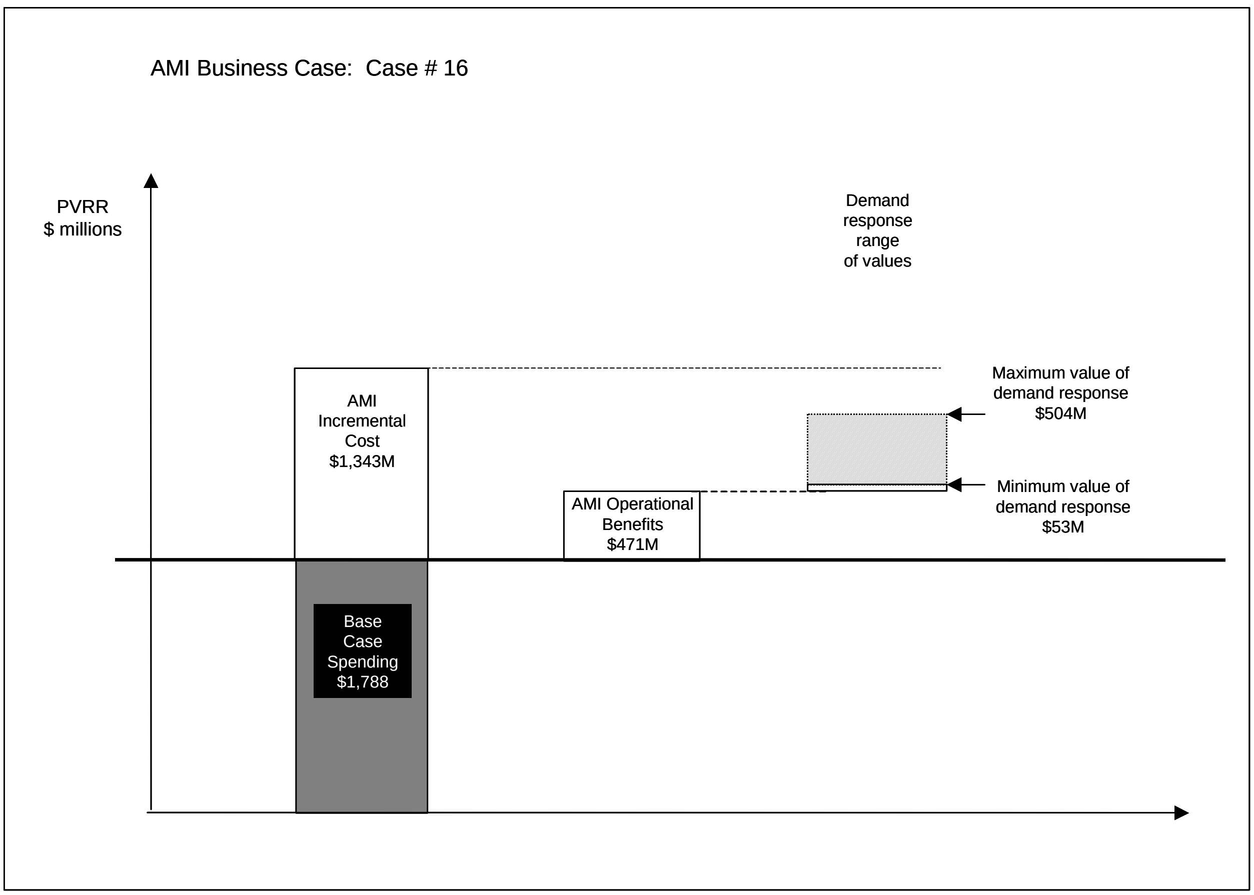
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and lower need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions	**-$34 to -$333**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$7 to -$67**	
Operations	MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($22)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($15)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/web based interval & power-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($0)	
Operations	XB-1	Existing Meter Tax write-off	($4)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($51)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($484)**	
		Demand Response - Minimum value	**(41)**	
		Demand Response - Maximum value	**(401)**	
	Total - System Cost		**$1,229**	
	AMI Operational Gap		**$746**	

AMI Business Case #16	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Used	Residential and small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – F, V	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$361.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$53 M to $504 M PVRR
Megawatt offload - by 2007 - by 2011	 32 MW to 302 MW 49 MW to 463 MW
Transmission & distribution benefits	$9 M to $82 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

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PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$57	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$932**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$18	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers with enabling technology	$76	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$412**	

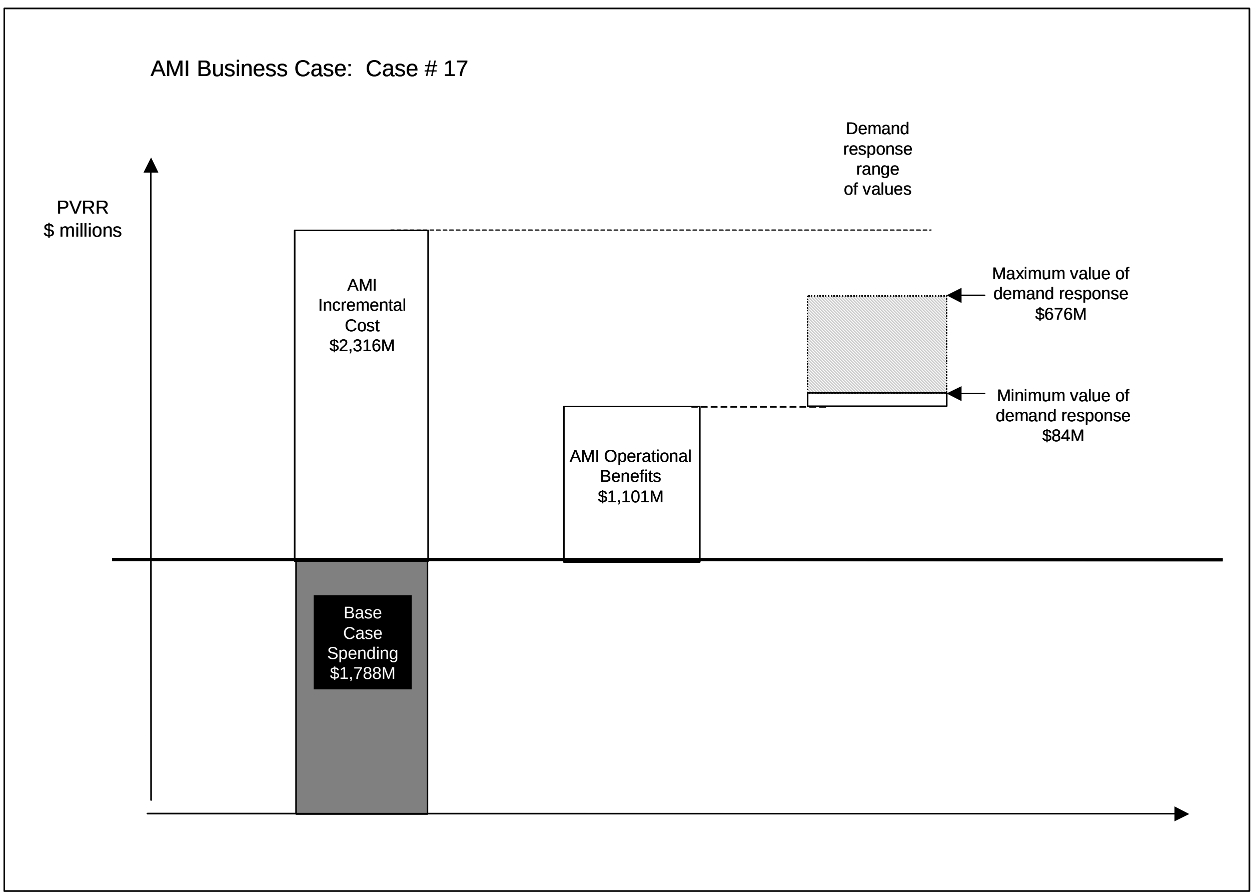
Total - Cost Components (Deployment & O&M)	**$1,343**

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and lower need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

AMI Business Case #17	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Not Used	Residential; used for small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff - Optional Tariff choices (Opt-In)	 Current CPP – F, V	 Current Tariff $0.75 per kWh on Critical Peak Days 15 CPP days per year

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$84 M to $676 M PVRR
Megawatt offload - by 2007 - by 2011	 30 MW to 250 MW 81 MW to 630 MW
Transmission & distribution benefits	$13 M to $106 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$243	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$20	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,820**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$2	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$26	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$27	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$497**	
		Total - Cost Components (Deployment & O&M)	**$2,316**	

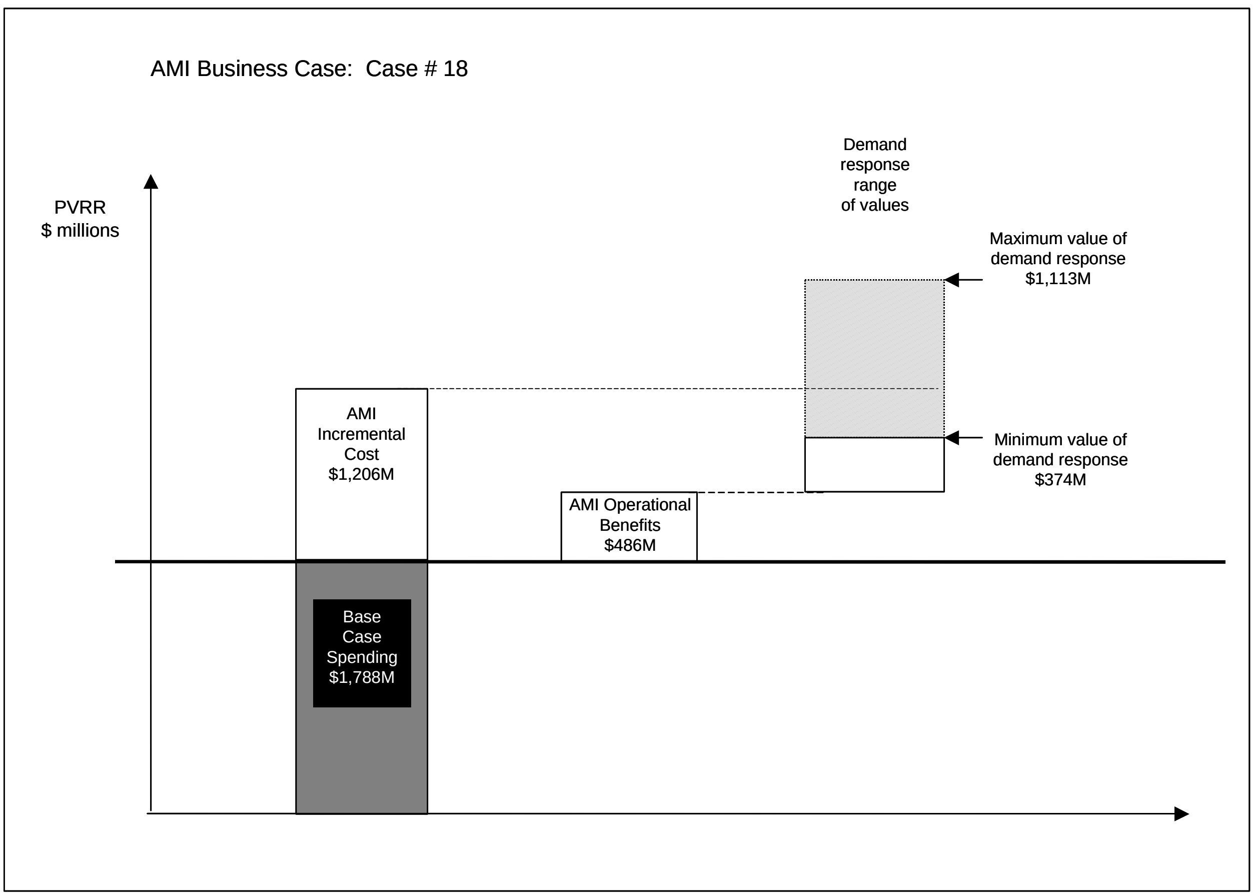
PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions	**-$71 to -$569**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$13 to -$106**	
Operations	MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/web based interval & power-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax write-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($169)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,101)**	
		Demand Response - Minimum value	**(84)**	
		Demand Response - Maximum value	**(676)**	
	Total - System Cost		**$2,316**	
	AMI Operational Gap		**$1,215**	

AMI Business Case #18	Assumptions	Rate Used
Deployment	Partial	3.7 million electric & gas meters
Deployment start & timeframe	March 2006	28 month build
Reliability enabling technology	Not Used	Residential or small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 CPP – P Current	 $0.75 per kWh on Critical Peak Days 15 CPP days per year Current Tariff

Case Summary and observations	
Total CIS implementation cost	$143.8 M
Meter reading benefits saved	$361.5 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$374 M to $1,113 M PVRR
Megawatt offload - by 2007 - by 2011	 229 MW to 671 MW 351 MW to 1,026 MW
Transmission & distribution benefits	$66 M to $162 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$63	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$194	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$2	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$354	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$23	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$233	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$874**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$11	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$24	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$46	
Operations	GS-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$11	
Operations	XC-2	Operations, maintenance & incentive payments on customers w ith enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$331**	

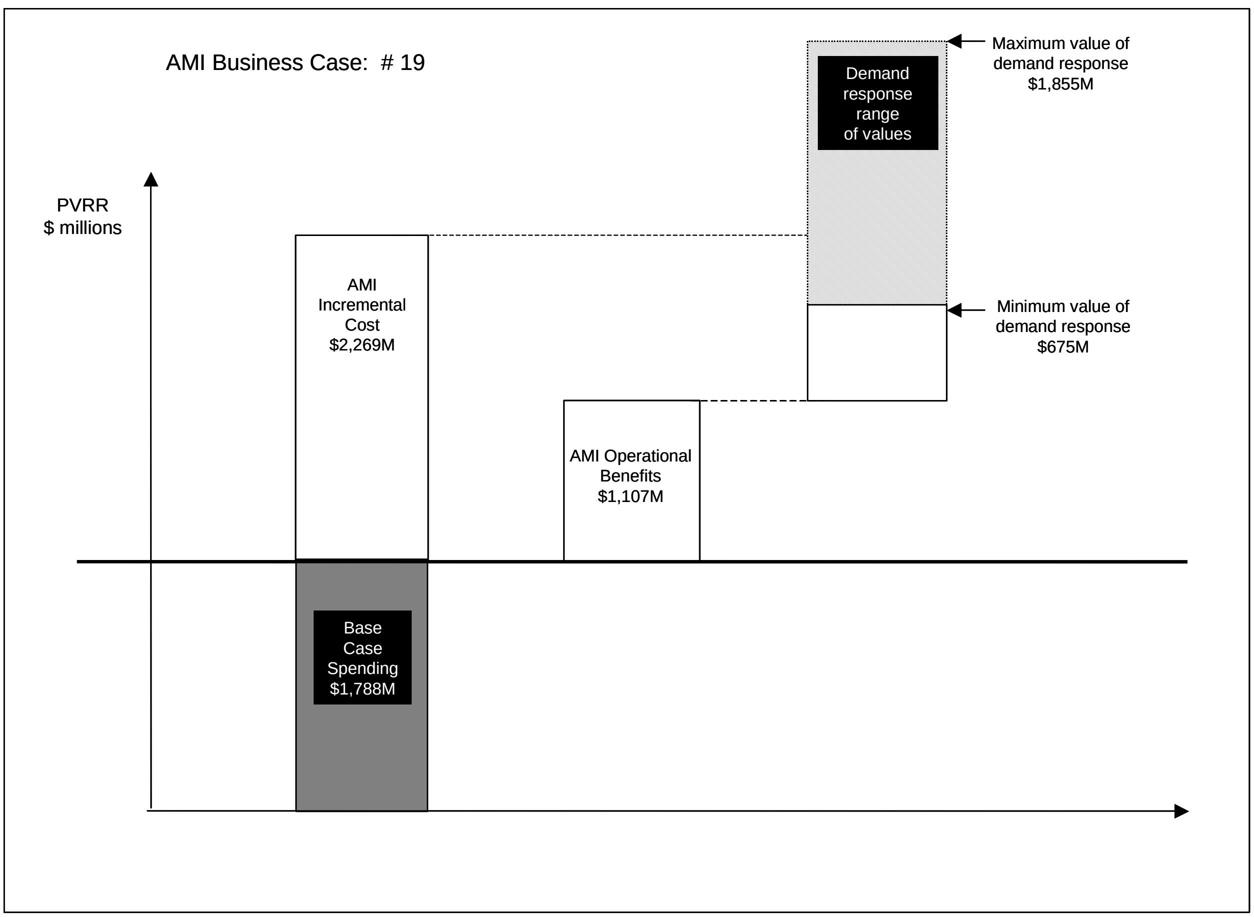
Total - Cost Components (Deployment & O&M)	**$1,206**

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($361)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and low er need for pickup reads	($1)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, w rong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated low er customer call volume (estimated / disputed bills)	($9)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($2)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($3)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($1)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($2)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($6)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($1)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

AMI Business Case #19	Assumptions	Rate Used
Deployment	Full	9.3 million electric & gas meters
Deployment start & timeframe	March 2006	48 month build
Reliability enabling technology	Not Used	Residential or small commercial
Demand Response	Enabled	
Tariff structure - Default Tariff (Opt-Out) - Optional Tariff choices	 CPP – P Current	 $0.75 per kWh on Critical Peak Days 15 CPP days per year Current Tariff

Case Summary and observations	
Total CIS implementation cost	$165.5 M
Meter reading benefits saved	$753.2 M PVRR
Monte Carlo simulation - Range of demand response values, including transmission & distribution benefits	$675 M to $1,855 M PVRR
Megawatt offload - by 2007 - by 2011	 267 MW to 700 MW 651 MW to 1,744 MW
Transmission & distribution benefits	$111 M to $273 M PVRR



PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Base	MS-12a	Cost of Maintaining Existing Metering Systems	$1,766	
Base	C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$22	
Base	I-8	Cost of Maintaining Existing hardw are and softw are that translates meter reads to customer bills	Included in SB-1	
		Total - Base Case	**$1,788**	

	Cost Components (Deployment)			
Deployment	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.	Included in I-2	
Deployment	C-2	Perform and review site surveys to determine placement of netw ork equipment	Included in C-10	
Deployment	C-3	Mapping of netw ork equipment on company facilities (asset facility mapping)	Included in C-10	
Deployment	C-4	Staging facilities for WAN/LAN equip and mounting hardw are (pre-installation)	$0	
Deployment	C-5	Review and develop strategies to retrieve data from meters and process w ithin billing system	Included in M-7	
Deployment	C-6	Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).	Included in C-10	
Deployment	C-7	Costs of Pole replacement - to "fit" concentrators	N.A.	
Deployment	C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	Included in 1-10	
Deployment	C-8b	Development of Internet based usage data communication	Included in M-3	
Deployment	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting	N.A.	
Deployment	C-10	Purchase netw ork communications equipment and hardw are	$95	
Deployment	C-11	Training for installation of WAN/LAN equipment (including install labor for w ireless circuits)	Included in C-10	
Deployment	I-1	Netw ork planning and engineering - coverage studies, tech selection, field testing & engineering	Included in M-7	
Deployment	I-2	Computing system implementation in data center (new hardw are/softw are, IT security review & compliance)	$243	
Deployment	I-3	Data center facilities	$0	
Deployment	I-4	Develop and process dynamic rates in CIS billing systems	Included in I-2	
Deployment	I-5	New information management softw are applications	Included in I-2	
Deployment	I-6	Records - databases, draw ings of field netw ork and data center servers	Included in I-2	
Deployment	I-7	Update w ork management interface to process additional volume of meter changes, data scripts	Included in MS-3	
Deployment	CU-1	Customer records/billing and collections w ork associated w ith roll-out of meter change process	Included in I-11	
Deployment	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	$6	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Deployment	CU-3	Modification and customer support costs for OIS and other system changes	Included in I-9	
Deployment	CU-4	Process meter changes for new meter installations and DA accounts	$0	
Deployment	MS-1	Additional temporary meter reading staff for transitional period/mtr reader transition costs	$0	
Deployment	MS-2	Administration of contracts/supervision of installer w orkforce	Included in M-7	
Deployment	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & softw are	$901	
Deployment	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)	Included in MS-3	
Deployment	MS-5	Installation labor (incl w orkers comp, P&B, payroll taxes, etc.)	Included in MS-3	
Deployment	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS	Included in MS-3	
Deployment	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs	Included in MS-3	
Deployment	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades	Included in MS-3	
Deployment	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters	Included in M-7	
Deployment	MS-11	Training (meter installers, handlers, shippers)	Included in MS-3	
Deployment	M-1	Buy out of Current SCE- or other utility ITRON Contract for 2000 ERT Deployment (350K meters)	N.A.	
Deployment	M-2	Meter RFP process and contract finalization and administration	Included in M-7	
Deployment	M-3	Customers access to usage information through communications medium	$4	
Deployment	M-4	Employee communications and change management	Included in M-14	
Deployment	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.	Included in M-4	
Deployment	M-6	Meter reader reroute administration (assuming gas meters are not included - w ill continue to be read)	$0	
Deployment	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	$26	
Deployment	M-8	Recruiting of incremental w orkers	Included in MS-3	
Deployment	M-9	Supervision/overhead of contracts and technology personnel assigned to hardw are and systems development	Included in M-7	
Deployment	M-10	Training for other traditional classifications (records, call centers, meter readers, T-men, etc)	$0	
Deployment	M-11	Work management tools	Included in MS-3	
Deployment	GS-1	Gas Index/Module Purchases	$524	
Deployment	GS-2	Purchase/replacement of non-retrofittable gas meters	Included in GS-1	
Deployment	XC-1	Purchases/replacement of enabling technology	$0	See Appendix C, Note 1
		Total - Cost Components (Deployment)	**$1,799**	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Cost Components (O&M)			
Operations	C-12B	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)	N.A.	
Operations	C-13	Costs of contracts to retrieve meter data and services	$0	
Operations	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	$3	
Operations	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules	Diminimus for this business case	
Operations	I-9	Aggregating, validating and creating billing determinant data for electric billing	$198	
Operations	I-10	Contract administration and database management of public network connections	$9	
Operations	I-11	Exceptions processing (develop, update, and execute data cleanup routines)	$20	
Operations	I-12	License and O&M software fees	Included in I-9	
Operations	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery	Included in I-9	
Operations	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)	Included in I-9	
Operations	I-15	Operating costs - retrieval and delivery of mtr, maint & outage information systems data and alarms	$26	
Operations	I-16	Server replacements (every 3-4 years) for 15 year life cycle	Included in I-2	
Operations	CU-5	Additional rate analysis due to multiple TOU options.	Included in CU-2	
Operations	CU-6	Cost of complying w / regulations - providing alternative safety measures (due to removal of electric mtr readers)	$0	See Appendix C, Note 2
Operations	CU-7	Cost of reduced customer safety (meter readers no longer available)	$0	See Appendix C, Note 3
Operations	CU-8	Customer education of rate changes/customer communications campaign	$9	
Operations	CU-9	Customer support for internet based usage data communication	$7	
Operations	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications	Included in M-14	
Operations	MS-12b	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)	Included in I-2	
Operations	MS-13	Pickup reads (remote retrieval not available/possible)	N.A.	See Appendix C, Note 4
Operations	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)	Included in MS-3	
Operations	M-12	Capital financing costs- discuss alternative methods of procuring the equipment or services (such as leasing or outsourcing) reviewed and rejected.	N.A.	See Appendix C, Note 5
Operations	M-13	Cost of increased load during mid-peak and off-peak periods	Included in DR-1	

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Operations	M-14	Customer acquisition and marketing costs for new tariffs	$19	
Operations	M-15	Risk contingencies (e.g., technology obsolescence/reliability)[1]		See Appendix C, Note 6
Operations	GS-3	Replacement of gas meter module, battery purchases and replacement labor	$54	
Operations	GS-4	Warehousing operations for gas modules	N.A.	
Operations	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	$100	
Operations	GS-6	Cost of complying w/ regulations - providing alternative safety measures (due to removal of gas mtr readers)	N.A.	See Appendix C, Note 7
Operations	GS-7	Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)	N.A.	See Appendix C, Note 8
Operations	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules	N.A.	
Operations	GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	$24	
Operations	XC-2	Operations, maintenance & incentive payments on customers with enabling technology	$0	See Appendix C, Note 9
		Total - Cost Components (O&M)	**$470**	

Total - Cost Components (Deployment & O&M)	**$2,269**

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
	Benefit Components			
Operations	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($753)	
Operations	SB-2	Field service savings (turn-on's / turn-off's) and lower need for pickup reads	($2)	
CustServ; not quantified	SB-3	Reduced energy theft-May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers (indirect benefit)	N.Q.	See Appendix C, Note 10
Operations	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($22)	
Operations	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($5)	
Operations	SB-6	Outage management benefits (momentary checking for PG&E)	($9)	See Appendix C, Note 11
Operations	SB-7	Better meter functionality / equipment modernization	($4)	See Appendix C, Note 12
Ops, not quantified	SB-8	Remote service connect / disconnect	N.Q.	See Appendix C, Note 13

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
Ops, not quantified	SB-9	Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads	N.Q.	See Appendix C, Note 14
Operations	SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and w hen they need to be replaced/repaired	($6)	
Ops, not quantified	SB-11	Reductions in Unaccounted for Energy (UFE)-CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all	N.Q.	See Appendix C, Note 15
Ops, not quantified	SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	See Appendix C, Note 16
Ops, not quantified	SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	See Appendix C, Note 17
Operations	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"	Included in SB-1	
Ops, not quantified	CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	See Appendix C, Note 18
Ops, not quantified	CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	See Appendix C, Note 19
Operations	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($14)	See Appendix C, Note 20
Ops, not quantified	CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	See Appendix C, Note 21
not quantified	CB-6	Customer rate choice / new rate options	N.Q.	See Appendix C, Note 22
not quantified	CB-7	Customized billing date	N.Q.	See Appendix C, Note 23
Operations	CB-8	Energy Information to customer can assist in managing loads	($2)	See Appendix C, Note 24
not quantified	CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	See Appendix C, Note 25
Operations	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($8)	
CustServ; not quantified	CB-11	On-line bill presentment w ith hourly data / more timely and accurate information about electricity / info access	N.Q.	See Appendix C, Note 26
not quantified	CB-12	Low er customer bills	N.Q.	See Appendix C, Note 27
not quantified	CB-13	Value to customers of more timely & accurate bills	N.Q.	See Appendix C, Note 28

PG&E Category	ACR Category	Description of Category	PV of Revenue Requirements (in millions)	Reference
DR	DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, low er net emissions	**-$564 to -$1,582**	
DR	DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.	Included in DR-1	
DR; not quantified	DR-3	Dynamic fuel sw itching / Dynamic integration of conventional and distributed supplies	N.Q.	See Appendix C, Note 29
DR	DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)	**-$111 to -$273**	
Operations	MB-1	Reduced equipment and equip maintenance costs (softw are maintenance & system support, handheld reading devices, uniforms, etc.)	($6)	
Operations	MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
Operations	MB-3	Reduced battery replacement / calendar resets / meter programming	($55)	
Operations	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	$0	
Operations	MB-5	Summary billing cash flow benefits (existing customers)	($36)	
CustServ; not quantified	MB-6	Possible reduction in "idle usage", meter w att losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	See Appendix C, Note 30
CustServ; not quantified	MB-7	Possible new rev source / new business ventures / new products & srvs/w eb based interval & pow er-quality data	N.Q.	See Appendix C, Note 31
Ops, not quantified	MB-8	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes	N.Q.	See Appendix C, Note 32
Ops, not quantified	MB-9	Tariff planning - more flexibility of rate contacts & options w ithin standard customer rate classes / dynamic tariffs	N.Q.	See Appendix C, Note 33
CustServ; not quantified	MB-10	Potential for tax savings from federal investment tax credits	N.Q.	See Appendix C, Note 34
Operations	MS-9	Salvage/Disposal process for removed meters	($1)	
Operations	XB-1	Existing Meter Tax w rite-off	($9)	See Appendix C, Note 35
Operations	XB-2	Post analysis period net benefits	($175)	See Appendix C, Note 36
		Total - Benefits (before demand response)	**($1,107)**	
		Demand Response - Minimum value	**(675)**	
		Demand Response - Maximum value	**(1,855)**	
	Total - System Cost		**$2,269**	
	AMI Operational Gap		**$1,162**	

APPENDIX C
Notes
Qualitative Assessments of Costs and Benefits

TABLE OF CONTENTS

The following items list specific categories for which PG&E provides a qualitative assessment. These qualitative assessments address either the uncertainty of an estimate or a non-quantified item. Non-quantified items are those items which PG&E cannot assess either due to lack of experience or lack of applicability.

<u>Costs</u>

<u>Note 1</u>
XC-1 – *Purchases of enabling technology:*

PG&E added this cost category for enabling technology. The deployment cost of the enabling technology required for small commercial customers with a CPP-V tariff in cases 8, 9, 10, 15, 16, 17 and for certain residential customers in cases 10, 12, 14, and 16 is included in this item. The cost of operations, maintenance, and incentive payments are addressed in XC2.

<u>Note 2</u>
CU-6 – *Cost of complying with regulations – providing alternative safety measures (due to removal of electric meter readers):*

PG&E is not aware of any electric safety regulations for which meter readers are responsible.

<u>Note 3</u>
CU-7 – *Cost of reduced customer safety (meter readers no longer available):*

PG&E acknowledges that meter readers sometimes find and report potential safety hazards in the course of performing their work. However, PG&E cannot quantify the cost of reduced vigilance due to the elimination of the meter reading function. Also see Note 8 (GS-7).

<u>Note 4</u>
MS-13 – *Pickup reads (remote retrieval not available/possible):*

PG&E does not expect to perform pick-up reads if remote retrievals are not available or possible. Instead, if remote retrievals fail, PG&E will issue a field order to investigate and correct the meter problem. Once corrected, the read data would be transmitted electronically.

<u>Note 5</u>
M-12 – *Capital financing costs- discuss alternative methods of procuring the equipment or services, such as leasing or outsourcing, reviewed and rejected:*

PG&E included an outsourced meter installation costs in all meter installation cases. With respect to outsourced financing, PG&E has not yet chosen a technology path or vendors. PG&E's analysis of bid responses from the RFP process will enable an assessment of contracting options and any cost differential between utility ownership and outsourcing. Therefore, PG&E has not developed a cost for this category at this time.

<u>Note 6</u>
M-15 – *Risk contingencies (e.g. technology obsolescence/reliability):*

PG&E included a risk contingency value in the deployment cost of the system. PG&E has not included or attempted to quantify additional risk contingencies in the cases. At this time, there is significant uncertainty regarding costs from outside vendors that may materially affect the costs for the business cases, such as: meters, network equipment, installation costs, computers, software licenses, and servers. PG&E is in an RFP process to more closely determine the costs of these items. Additionally, RFP results will provide better cost estimates for items such as meter reliability or failure rates, obsolescence, warranty costs, and PG&E will be able to refine its risk contingency once a technology strategy is decided.

<u>Note 7</u>
GS-6 – *Cost of complying with regulations – providing safety measures (due to removal of gas meter readers):*

The only gas safety regulation performed by PG&E's gas meter readers is atmospheric corrosion inspections. These costs are included in the analysis in item GS-9. PG&E knows of no other costs fit this category.

<u>Note 8</u>
GS-7 – *Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently meter readers):*

See Note 3 (CU-7) and Note 10 (SB-3).

<u>Note 9</u>
XC-2 – *Operations, maintenance & incentive payments on customers with enabling technology:*

PG&E has added this cost category for enabling technology. The on-going cost of the operations, maintenance, and incentive payments for small commercial customers with a CPP-V tariff in cases 8, 9, 10, 15, 16, 17 and for certain residential customers in cases 10, 12, 14, and 16 are included in this item. The deployment cost of the enabling technology is addressed in XC1.

<u>Benefits</u>

<u>Systems Operations Benefits</u>

<u>Note 10</u>
SB-3 *Reduced energy theft - May provide ability to ID active accounts for metered accounts not being billed, broken meters, wrong multipliers:*

Implementing AMI is likely to impact PG&E's ability to identify lost revenue in two ways. First, by visiting 100% of PG&E's meter locations it is anticipated that some of the accounts affected by theft could be detected during the AMI meter installation process. The installation process may also reveal meter or billing characteristics errors (e.g. billing constants, locations, lost meters, etc.) as well as broken or damaged meters. Second, once the AMI system is in place, PG&E anticipates that additional information could be available that will indicate the health of the meter as well as providing "tamper alarms" that will aid in more rapid identification and correction of potential tampering conditions.

Even if the potential reduction in energy theft could be quantified, it would represent a shift in cost responsibility among customers, rather than a reduction in total costs charged to customers as a whole.

Note 11
SB-6 *Outage management benefits (momentary checking for PG&E):*

In addition to the direct operational savings identified, PG&E anticipates that outage-related information provided by an AMI system will enable PG&E to improve service to customers through better information related to customer's individual power status and by enhancing PG&E's ability to potentially reduce the duration of outages and speed restoration efforts. Depending on the technology selection, PG&E will re-evaluate outage management benefits.

Note 12
SB-7 *Better meter functionality / equipment modernization:*

Full deployment of AMI involves the replacement of all existing electric meters over the deployment period with either new AMI meters or refurbished existing meters, recalibrated and fitted with AMI modules. This replacement process would result in a newer fleet of potentially more accurate meters due to their lower average years of installed service. PG&E believes this replacement process has the potential to slightly improve overall or average meter accuracy. Additionally, PG&E believes that due to the commercial availability of meters, it is anticipated that if AMI meters were deployed a number of the replacement meters would be solid state meters. Solid state meters have the potential to provide other accuracy related benefits, such as lower starting watts or increased accuracy in metering demands versus existing electromechanical meters. PG&E believes that each of these factors has the potential to make small increases in the overall accuracy of PG&E's metering. However, without a final determination on the technology selection, and a final count of new meter replacements, this benefit cannot be quantified.

Even if the potential improvement in meter accuracy could be quantified, it would represent a shift in cost responsibility among customers, rather than a reduction in total costs charged to customers as a whole.

Note 13
SB-8 *Remote service connect / disconnect:*

One of the potential functions that could be enabled by some AMI systems is the capability for the utility to remotely connect or disconnect the electric service to customers. Adding the capability to perform remote service connects and disconnects requires additional and relatively costly hardware at each customer location and PG&E does not include the costs or resulting benefits of this hardware in the business cases. PG&E considers a remote service connection/disconnection feature as a possible system enhancement in certain locations after a decision about deployment of the AMI system. Without a final determination on technology, PG&E cannot quantify this benefit.

Note 14
SB-9 *Meter accuracy- improved and more timely load information could increase forecasting accuracy and reduce resource acquisition costs and reduced customer complaints about faulty meter reads:*

An hourly electric demand forecast is one of the key variables used by PG&E to: (1) schedule/dispatch retained-generation and purchased power contracts and (2) procure/sell power in the market place. For short-term (one month through two years) operations and procurement decision making, PG&E uses a model to develop load forecasts. This model relies on historical hourly temperature and hourly California Independent System Operator (ISO) settlement load data.

The historic settlement data now depends on monthly meter reads and an "average" rate group level load profile curve. AMI meters could supply more data points for any sample of customers desired, and therefore could lead to more accurate estimates of load inputs to the forecast model. Depending on costs, interval meters read daily could provide increased segmentation of customers and their current weather response in demand to be estimated daily as forecast inputs. Since ISO imbalance energy prices change on a ten-minute basis, there may be a net financial impact to improved forecast accuracy when forecasts 1) more closely match settlements, and 2) allow more cost efficient short term market purchases. A precise quantification of the benefit is difficult since isolating it is difficult. For instance, differences between forecasted and actual electric usage may be the result of temperature changes.

Even if the potential improvement in meter accuracy could be quantified, it would represent a shift in cost responsibility among customers, rather than a reduction in total costs charged to customers as a whole.

Note 15
SB-11 *Reductions in Unaccounted for Energy (UFE) - CEC and ISO studies have identified significant percentages of total system energy deliveries that cannot be accounted for by retail sales or transmission losses. AMI systems identify the source and solution for these problems and reduce energy costs for all customers:*

UFE is an energy imbalance that cannot be assigned to a responsible party. Imbalance charges are based the difference between scheduled energy and actual metered consumption. In theory all energy can be accounted for through the aggregation of all generation meters, load meters, metered tie points at the Utility Distribution Company's (UDC) boundaries, and transmission and distribution losses. The sources of UFE include meter error, statistical load profiling error, distribution loss deviation, transmission loss deviation, meter data processing errors, and energy theft (i.e., unmetered energy consumption).

Information from AMI meters addresses some of the causes of UFE directly, namely statistical load profiling error and timely collection of meter data (including estimation). As improved measures of interval data at the customer segment level can improve forecasts to reduce imbalance charges, see Note 14 (SB-9) above, interval meter reading accuracy and timeliness will reduce UFE by improving the accuracy of the interval level ISO settlement data. However, as discussed in Section V. A. 2, even if the potential reduction in UFE could be quantified, it would represent a shift in cost responsibility among customers, rather than a reduction in total costs charged to customers as a whole.

Note 16

SB-12 *Ability to monitor customer self generation into system on a real time basis:*

It was unclear to PG&E how to interpret this item. Therefore, PG&E did not analyze the monitoring of customer self-generation into the system on a real time basis within this report.

Note 17

SB-13 *Reduction in the amount of time to implement new rates and or load management programs:*

Interval metering installed for all customers will result in a quicker implementation of demand response programs and other tariff related programs. Interval data from the meters will assist in the development of the programs and rates, giving PG&E the ability to more closely match the program load reduction potential or rate potential with targeted customers' profiles. Currently program development is handled using statistical samples; actual data should improve future analysis. No dollar benefits are identified, since data analysis would have to be done in either case.

Customer Service Benefits

Note 18

CB-2 *Early detection of meter failures and distribution line stresses can reduce outages and improve customer service:*

Improvements related to metering and meter accuracy are included in SB-7. In addition to the CPUC's specified benefits, an AMI system has the potential to create additional benefits in this area. The following are three examples of incremental benefits that are realistically achievable with AMI but that have not as yet been widely explored by the industry and that are not included in PG&E's business case.

1. Depending on the AMI system, it is possible that small commercial and industrial customers with CTs and PTs could detect under-registration of energy use problems earlier. This early detection would lead to increased customer satisfaction, since problems such as this otherwise can go undetected for 30 days or more.

2. The availability of hourly data for all customers could enable PG&E, with the appropriate additional software and other tools, to analyze loads along the feeder and its components, including distribution transformers, rather than for just the entire feeder as is done today. This would help to determine which portions of the feeder may benefit from upgrades.

3. The availability of continuous interval load and or voltage data from selected monitoring points on a feeder could also be used to improve VAR management capabilities resulting in improved customer satisfaction, avoided brownouts and other consequences.

Note 19

CB-3 *May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions:*

PG&E does not anticipate that meter installers will have the time to inspect panels any more than is necessary to ensure a safe meter installation as part of the normal meter change work. In the case of unsecured meters, PG&E described the benefit for damaged or tampered meters in SB-3. PG&E does not anticipate any incremental benefits gained from the opportunity to inspect panels and reattach unsecured meter boxes during AMI deployment.

Note 20

CB-4 *Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing:*

PG&E expects that AMI system customers should receive timely and more accurate bills containing fewer estimated reads or meter reading errors and those savings are noted in the benefit calculation. However, PG&E is not able to estimate any incremental benefits due to this improvement.

Note 21

CB-5 *Customer energy profiles for EE / DR targeting (marketing)*

PG&E currently obtains most of the data now required to market load management programs from existing load profiling equipment for rates and load management programs. PG&E recognizes that, with AMI, more data points would be available and that data could become more detailed and statistically significant, however, PG&E is unable to estimate a dollar benefit for this item.

Note 22
CB-6 *Customer rate choice / new rate options*

Interval metering will make it possible to provide all customers with additional information to help them choose the best rate options for their service. Currently, customer selection of a new time-of-use rate or demand response rate program often requires making educated "best estimates" about a customer's electric load profile. Customer assignment to new rates or programs occurs after necessary metering and communications equipment has been installed. No specific dollar benefit is attributed to these benefits.

Note 23
CB-7 *Customized billing date:*

New information provided from AMI meters could provide some customers with certain choices about when it would be best to bill them for gas and electricity usage. Customer survey comments indicate that customers would like to have these kinds of options and that they view this as an added service benefit from PG&E. Options for customized billing dates could provide certain customers with more flexible payment arrangements and ultimately reduce credit follow-up and potential calls to PG&E call centers and credit personnel. Combined with online bill viewing and payment options, PG&E believes this information has the potential to add future customer value. No specific dollar benefit is attributed to these benefits.

Note 24
CB-8 *Energy Information to customer can assist in managing loads:*

AMI can provide customer load and usage information to assist customers in managing their own usage and ultimately their gas and electric bills. If customers have access to this information, PG&E believes it will provide customers with answers to many of their own usage and billing questions. PG&E assumes that with this information, customers will either avoid calling at all, or customers calling to inquire about potentially high bills will need to spend less of their time with a PG&E service representative discussing usage and energy costs. PG&E's estimate of the direct call center benefits is the included cost/benefit analysis. However, PG&E is not able to estimate the benefits associated with the customer side of this improvement. PG&E also assumes that customers who have access to their data will view this usage information and make changes to their usage consumption. (See note to CB-11.)

Note 25
CB-9 *Enhanced billing options could be a source of revenue and increased customer satisfaction:*

See Note 31 (MB-7) for PG&E's view on quantifying the benefits associated with potentially new products and services.

Note 26
CB-11 *On-line bill presentment with hourly data / more timely and accurate information about electricity / info access*

Customers that enjoy services like on-line banking will appreciate having on-line information regarding their PG&E bill – in particular if energy usage and energy pricing information is available to them. It is expected that customers will utilize this information to help control and change usage patterns to lower their bills. Access to this information will be perceived as a service benefit from customers likely to use on-line services. PG&E at this time assumes that customers may make more use of PG&E's Customer Service On-line (CSOL) services, which could result in fewer calls to call center service representatives. PG&E is unable to assess a net benefit for this category at this time.

Note 27
CB-12 *Lower customer bills*
Reduced customer bills can become an outcome of an AMI program, and are quantified as part of the demand response program.

Note 28
CB-13 *Value to customers of more timely & accurate bills:*

See Notes 20 (CB-4) and 23 (CB-7).

Demand Response Benefits

Note 29
DR-3 *Dynamic fuel switching / dynamic integration of conventional and distributed supplies:*

It was unclear to PG&E how to interpret this item. Therefore, PG&E has not analyzed dynamic fuel switching within this report.

Management and Other Benefits

Note 30
MB-6 *Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes*

See note 12 (SB-7).

Note 31
MB-7 *Possible new revenue source / new business ventures / new products & services/web based interval & power-quality data (new business ventures):*

An AMI system could enable a new array of functional capabilities. However, it is too early to know whether any of these potential new functional capabilities can (or should) be leveraged into new business ventures and if any of those new products or service offerings would be profitable.

Note 32

MB-8 *May facilitate ability to obtain GPS reads during meter deployment-improving Franchise & Utility Users Tax processes:*

Franchise fees are calculated by measured centerline footage of primary overhead and underground lines and gas mains. Since meter locations do not indicate the footage of lines and pipes, AMI deployment is not expected to provide benefits to the franchise tax process.

Note 33

MB-9 *Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs:*

See Note 17 (SB-13).

Note 34

MB-10 *Potential for tax savings from change to federal tax depreciation recovery period:*

Pending federal tax legislation could change PG&E's assumption of a 20 year tax depreciation period for all of the AMI assets. However, PG&E has not included it in the analysis at this time.

Note 35

XB-1 *Existing meter write-off:*

PG&E added this benefit category. The benefit of accelerating tax depreciation for the portion of meters retired that have a remaining tax basis is included in this item and is reflected in the business case.

Note 36

XB-2 *Post analysis period net benefits:*

PG&E added this benefit category. PG&E assumed that the AMI metering & related network have an effective useful life which extends beyond the last year, 2021, requested for the analysis period for the business cases. To value the net benefits beyond this period, PG&E calculated a net benefit for the remaining useful life of the AMI network placed in service in the deployment years of 2006 – 2010. In 2022-2025, it is assumed that 100% of the continuing net benefits belong to this AMI meter deployment. In 2026-2030, it is assumed that a second AMI deployment begins that would replace all remaining meters and infrastructure from this business case. A net benefit is calculated for those years in proportion to a new buildout. The post analysis net benefits are then presented in 2004 dollars.

APPENDIX D

Assumptions used in the Demand Response Modeling Analysis

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APPENDIX D

Assumptions used in the Demand Response Modeling Analysis

Introduction

The impact estimates for customers with demands below 200 kW contained in this filing were developed for PG&E by Charles River Associates (CRA). The basic methodology used to develop impact estimates is documented in the body of the submission. This appendix, along with accompanying workpapers, documents the development of the input values for all variables used in CRA's cost-effectiveness model (CEM).

Four key variables involved in the estimation of demand response are documented in the following four sections of this appendix:

1. Energy use by rate period for customers in the target population prior to the introduction of alternative rate options;

2. Price elasticities, which are used to predict the change in energy use by rate period for the average customer on a new rate option;

3. Specific prices in each rate period under the existing and alternative rates;

4. An estimate of the number of customers that will select each rate option (e.g., participation rates).

In addition to these key variables, the CEM requires a variety of other input variables, which are discussed in Section D5.

In order to address the uncertainty inherent in some of the input values used for the analysis, CRA used a Monte Carlo simulation to develop a probability distribution of benefit estimates based on a range of customer price elasticities (e.g., the elasticity of substitution and the daily price elasticity). The range of elasticity estimates used for this simulation is discussed in Section D3. High and low estimates of participation rates were combined with high and low values for elasticities to produce the range of impact estimates reported in Appendix B. These high and low participation rate values are discussed in Section D4 below.

It is important to note that this preliminary analysis did not model impact estimates for the winter period.[1] Previous work by CRA, for PG&E, indicated that only a small proportion of total avoided capacity and energy benefits accrue during the winter period, primarily because CPP rates do not apply during the winter. In light of this, and the fact that winter elasticity estimates are not yet available from the SPP, PG&E decided not to conduct analysis for the winter period. Thus, no winter prices or other input values were developed for the winter.

[1] The summer period for all rates is from May 1 through October 31 and the winter period covers all other days.

Before turning to a discussion of the various input values, it is useful to understand the characteristics of the four time-varying rates being examined.

- **Time of Use (TOU):** For residential customers, the TOU tariff has two rate periods. The peak period is from 2 pm to 7 pm on weekdays and the off-peak period is all other times. For PG&E's small commercial and industrial (C&I) customers already on a TOU rate, it was assumed that there would be no incremental demand impact from these customers for ACR scenarios involving TOU rates. For small C&I customers not already on TOU rates, the TOU rate examined has the same peak period that currently exist for PG&E's current TOU customers, which goes from 12 pm to 6 pm in the summer.

- **Critical Peak Pricing—Fixed (CPP-F):** The CPP-F tariff has two rate periods on all weekdays in both the summer and winter seasons for both residential and C&I customers. For 15 CPP days during the summer period, the peak-period price is significantly higher than on non-CPP days. CPP notification occurs the day before a critical peak day. The peak period for both CPP and non-CPP weekdays is from 2 pm to 7 pm for residential customers and from 12 pm to 6 pm for C&I customers during the summer period.

- **Critical Peak Pricing—Variable (CPP-V):** There are two primary differences between CPP-F and CPP-V tariffs. First, for the CPP-V tariff, notification can occur the day of a CPP event. Second, the length of the critical period for the CPP-V rate can vary. However, for simplicity in this analysis, we modeled the CPP-V rate as if the control period covered the entire peak period on CPP days (e.g., a five-hour period for residential customers and a six-hour period for small C&I customers).

- **Critical Peak Pricing—Pure (CPP-P):** This tariff differs from the previous three tariffs in that it has a time-varying rate only on CPP days. That is, on all non-CPP weekdays and weekends, prices do not vary by time of day. The peak-period price on CPP days for this tariff is assumed to be essentially the same as for the other CPP tariffs. However, the off-peak price is much higher than for the CPP-F or CPP-V tariffs, because there are many more off-peak hours in this tariff than for any of the other tariffs and revenue neutrality dictates that only a small discount can be given during the off-peak period compared with the current average price.[2]

In addition to the characteristics described above, some customers are given the choice of obtaining enabling technology that will help them respond to time-varying prices. PG&E assumes that enabling technology would only be offered to customers with central air

[2] See Section D3 below for a summary of the average prices in each rate period for existing and new tariffs.

conditioners who are on one of the CPP tariffs but would not be offered to any customers on a TOU tariff. Since the vast majority of small C&I customers have central air conditioning (CAC), for simplicity, this analysis assumes that 100 percent of small C&I customers have CAC.

D1. Average Energy Use

Estimates of average energy use by customer segment under existing rates were developed from a combination of PG&E's load research sample and billing file information. The following steps were implemented to arrive at average energy use by rate period for the starting year, 2003.

1. PG&E provided CRA with aggregate load information by climate zone based on 2002 load research data for the following rate classes: E1, A1, A6, A10(non-TOU)[3] and E19V (for customers with loads between 50 and 300 kW).[4] As discussed in section D2, 2002 represents PG&E's average (e.g., 1-in-2) load year.

2. CRA used the load data described in (1) to compute the share of average monthly energy use consumed in each rate period for each customer class (e.g., peak and off-peak periods on CPP days, peak and off-peak periods on non-CPP weekdays, all day on weekends and holidays). The CPP day shares were based on a random draw of 15 out of the top 25 system load days for 2002. Shares for each rate class are reported in the last four columns of Tables 1 through 5 below.

3. PG&E provided CRA with data on aggregate energy use and average customer months for each rate class for the summer and winter of 2003 based on PG&E's billing data. CRA used the summer data to compute average monthly energy use for summer 2003.[5] These values are reported in the last rows of Tables 1 through 5. The data for E1 customers reported in Table 1 includes all of PG&E's domestic rates, including roughly 100,000 customers on the E7 TOU rate. The small percent of total load associated with these customers did not merit separate analysis.

4. The shares computed in step (2) were applied to the monthly averages computed in step (3) to derive energy use by rate period for 2003, the starting year of the analysis. The resulting values are reported in Tables 1 through 5.

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[3] PG&E also has about 2,400 C&I customers on an A10-TOU rate. However, the vast majority of A10-TOU customers have peak demands exceeding 200 kW and, therefore, already have interval meters. Thus, they were excluded from the analysis.

[4] PG&E has load data for three groups of E19V customers, those with demands less than 50 kW, those with demands between 50 and 300 kW and those with demands greater than 300 kW. The middlestrata represents the largest share of E19V customers overall and was used as a proxy for the target segment (e.g., E19V customers with demands below 200 kW).

[5] Data on the number of customers used in this calculation is reported in Table 26 at the end of this Appendix.

Table 1
Average Monthly Electricity Use For Residential Customers

Day Type	Rate Period	Summer kWh				% Monthly kWh			
		T	X	S	R	T	X	S	R
CPP Day	Peak	6	13	24	26	2	2	3	3
	Off-Peak	24	36	59	64	6	7	8	8
Non-CPP Day	Peak	49	75	111	121	13	14	14	15
	Off-Peak	187	253	343	361	49	46	44	44
Weekend	All Day	118	166	235	252	31	31	30	31
Total		384	544	773	824	100	100	100	100

Table 2
Average Monthly Electricity Use For A-1 Customers

Day Type	Rate Period	Summer kWh				% Monthly kWh			
		T	X	S	R	T	X	S	R
CPP Day	Peak	33	56	47	43	3	4	4	3
	Off-Peak	82	94	85	89	6	6	7	7
Non-CPP Day	Peak	241	357	304	268	19	23	24	20
	Off-Peak	601	654	564	589	46	43	44	45
Weekend	All Day	338	374	288	333	26	24	22	25
Total		1295	1535	1287	1323	100	100	100	100

Table 3
Average Monthly Electricity Use For A-6 Customers

Day Type	Rate Period	Summer kWh				% Monthly kWh			
		T	X	S	R	T	X	S	R
CPP Day	Peak	146	273	299	290	3	4	4	3
	Part-Peak	159	233	272	285	3	3	3	3
	Off-Peak	201	230	264	321	4	3	3	4
Non-CPP Day	Peak	1062	1752	1928	1826	19	23	24	20
	Part-Peak	1168	1577	1791	1865	20	21	22	21
	Off-Peak	1479	1630	1782	2143	26	22	22	24
Weekend	All Day	1489	1832	1822	2268	26	24	22	25
Total		5704	7528	8158	8998	100	100	100	100

Table 4
Average Monthly Electricity Use For A-10 (Non-TOU) Customers
With Peak Demands <200kW

Day Type	Rate Period	Summer kWh				% Monthly kWh			
		T	X	S	R	T	X	S	R
CPP Day	Peak	546	622	624	648	3	3	4	4
	Off-Peak	918	1127	1135	1096	6	6	6	6
Non-CPP Day	Peak	3876	4212	4091	4324	25	23	23	24
	Off-Peak	6742	7933	7696	7539	43	43	44	43
Weekend	All Day	3516	4468	4002	4116	23	24	23	23
Total		15598	18361	17547	17723	100	100	100	100

Table 5 Average Monthly Electricity Use For E-19-Voluntary Customers With Demands <200 kW									
Day Type	**Rate Period**	**Summer kWh**				**% Monthly kWh**			
		T	**X**	**S**	**R**	**T**	**X**	**S**	**R**
CPP Day	**Peak**	704	734	780	787	3	3	3	3
	Part-Peak	737	776	822	826	3	3	3	3
	Off-Peak	900	980	1021	1032	3	3	3	3
Non-CPP Day	**Peak**	4962	5128	5480	5561	19	18	19	19
	Part-Peak	5290	5520	5865	5910	20	20	20	20
	Off-Peak	6587	7132	7437	7491	25	25	25	25
Weekend	**All Day**	7164	7841	8059	8095	27	28	27	27
Total		26345	28110	29464	29703	100	100	100	100

D2. Price Elasticities

The demand response impact estimates are determined by the response of customers to the time-varying price signals associated with the new rates. The demand models underlying the residential sector analysis are based on results from California's Statewide Pricing Pilot (SPP) and are described in the Summer 2003 SPP report.[6] The two summary measures of price response used in this analysis are the elasticity of substitution and the daily price elasticity of demand. As described below, the residential elasticities used in the analysis are largely based on the SPP analysis, which represents a statewide population of customers in each climate zone. The SPP elasticities were adjusted based for the weather conditions and CAC saturations representative of populations in PG&E's climate zone.

The small C&I elasticities are largely based on previous studies, except for the technology-enabled options, which are based on the CPP-V rate analysis from the SPP.

D2a. Residential Elasticities

For the residential sector analysis, the impact estimates are based on price elasticities derived from the SPP, tailored to reflect the weather conditions and CAC saturations of PG&E's customers. Equation (3) in section 4.2.1 of the Summer 2003 SPP report, which, for convenience, is shown below, was estimated from data on SPP customers in the CPP-F treatment and control cells.

[6] Charles River Associates, Inc. *Statewide Pricing Pilot Summer 2003 Impact Analysis*. August 9, 2004 (Published October 11, 2004)

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = \alpha + \sum_{i=1}^{N}\theta_i D_i + \sigma \ln\left(\frac{P_p}{P_{op}}\right) + \delta(CDH_p - CDH_{op}) + \lambda(CDH_p - CDH_{op})\ln\left(\frac{P_p}{P_{op}}\right) + \phi(CAC)\ln\left(\frac{P_p}{P_{op}}\right) + \varepsilon \quad (1)$$

where

Q_p = average daily energy use per hour in the peak period

Q_{op} = average daily energy use per hour in the off-peak period

σ = the elasticity of substitution between peak and off-peak energy use

P_p = average price during the peak pricing period

P_{op} = average price during the off-peak pricing period

δ = measure of weather sensitivity

CDH_p = average cooling degree hours per hour (base 72 degrees) during the peak pricing period[7]

CDH_{op} = average cooling degree hours per hour (base 72 degrees) during the off-peak pricing period

θ_i = fixed effect for customer i

D_i = a binary variable equal to 1 for the i^{th} customer, 0 otherwise, where there are a total of N customers.

ε = regression error term.

The composite elasticity of substitution (ES) in this model is a function of three terms, as shown below:

$$\text{ES}=\sigma + \lambda(CDH_p - CDH_{op}) + \phi(CAC) \quad (2)$$

The estimated values for σ, λ and ϕ are, respectively, -.02054, -.00538 and -.03202. The elasticities for the base case residential analysis were derived by multiplying the coefficients in equation 2 by the CAC saturations for each of PG&E's four primary climate zones and by the values for the weather term for each zone and day type. The same equation was used to estimate elasticities for the CPP-F and TOU rates.

The daily elasticities reported in the table are derived in a similar manner (i.e., by substituting the relevant weather and CAC saturation data into the daily model estimated from the SPP data). The model is similar to the one shown above except that the

[7] The difference in cooling degree hours was used in the Constant-Elasticity of Substitution (CES) demand model specification rather than the ratio of cooling degree hours in the two time periods because, in some climate zones, the value for off-peak cooling degree hours equals 0. In these cases, calculating the ratio would involve dividing by zero.

dependent variable is daily electricity use rather than the ratio of daily use in each period, and the price term is average daily price. The coefficients on the price term alone, the interaction between weather and price, and the interaction between CAC saturation and price, are, respectively, -.03970, -.00306 and +.06365.

Estimate of the saturation of central air conditioning used in equation 2 for residential customers in PG&E's service territory, shown in Table 6, were based on the California Energy Commission 2003 California Statewide Residential Appliance Saturation Survey data for the PG&E research climate zones.

Table 6
PG&E Central Air Conditioning Saturations

PG&E Climate Zone	CAC Saturation (%)
T	3.7
X	34.9
R	61.8
S	65.3
All	37.9

The weather data underlying the residential price elasticities is based on a "1-in-2" weather year. PG&E identified both 1-in-2 and 1-in-10 weather years after examining 22 years of weather data. To determine the 1-in-2 and 1-in-10 weather years, the 22 years were rank ordered based on average temperature in PG&E's service territory during the summer peak period. The 1-in-2 year was determined to be rank 11 and the 1-in-10 year was rank 21. In this manner, 2002 was determined to be a typical year (1-in-2) and 2001 was determined to be the extreme year (1-in-10). Average temperature in the summer peak period equaled 77.8 degrees F in 2002 and 79.7 degrees F in 2001—that is, there is only a two-degree difference in the average peak period temperature between the 1-in-2 and 1-in-10 weather years.

Table 7 contains estimates of the weather variables used to compute price elasticities. Recall from the definition of variables following equation 1 that the weather variable used to estimate the elasticity of substitution equals cooling degree hours per hour (base 72) in the peak period minus cooling degree hours per hour in the off-peak period. The variable used in the daily elasticity equation equals average cooling degree hours per hour per day.

Table 7 Weather Data Used To Compute Price Elasticities						
Year	**Climate Zone**	**CPP Days**		**Non-CPP Days**		**Weekends**
		CDH/hr (Peak-Off Peak)	**Daily CDH/hr**	**CDH/hr (Peak-Off Peak)**	**Daily CDH/hr**	**Daily CDH/hr**
1-in-2	**T**	3.42	1.34	0.06	0.03	0.24
	X	12.59	5.49	1.90	0.69	1.40
	S	17.02	9.24	8.05	3.30	4.08
	R	17.72	12.38	11.23	6.58	7.41
1-in-10	**T**	2.15	1.02	0.13	0.05	0.18
	X	11.63	5.67	2.84	0.94	1.50
	S	18.04	10.80	8.98	3.59	4.71
	R	19.00	15.12	12.42	7.05	8.62

As seen in Table 7, in most instances, the differences between the values in the 1-in-2 and 1-in-10 years are small. It is also worth noting that the values for the 1-in-10 year are not always larger than the values for the 1-in-2 year for all zones. For example, the values for the "difference variable" underlying the elasticity of substitution are smaller in the 1-in-10 year than in the 1-in-2 year for zones T and X, and larger for zones S and R. This results because the selection process focused on average temperature in PG&E's service territory rather than on cooling degree hours in each climate zone. As a result, price responsiveness, as measured by the elasticity of substitution, is actually smaller in zones T and X based on the 1-in-10 weather year than it is based on the 1-in-2 weather year. The opposite is true for zones S and R. Overall, the difference in impacts between the two weather scenarios is only about 2 percent, based on a 75-cent CPP-F rate scenario, with the 1-in-10 year weather producing the larger of the two estimates. This difference is completely nested within the broader range of the Monte Carlo simulation estimates that have been developed. Consequently, CRA did not separately model the 1-in-10 weather-year scenario.

Table 8 shows the values for the elasticity of substitution and the daily price elasticity based on PG&E data for residential central air conditioning saturations and weather for the 1-in-2 weather year.

Table 8
Base Case Elasticities for Residential CPP-F and TOU Scenarios
(1-in-2 Weather Year Data)

Climate Zone	Day Type	CPP-F		TOU		CPP Tech Enabled	
		Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity
R	CPP	-0.14	-0.04	-0.11	-0.02	-0.49	-0.04
	Non-CPP	-0.10	-0.02	-0.11	-0.02	-0.10	-0.02
	Weekend	n/a	-0.10	n/a	-0.10	n/a	-0.10
S	CPP	-0.13	-0.03	-0.09	-0.01	-0.48	-0.03
	Non-CPP	-0.08	-0.01	-0.09	-0.01	-0.08	-0.01
	Weekend	n/a	-0.11	n/a	-0.11	n/a	-0.11
T	CPP	-0.04	-0.04	-0.03	-0.04	-0.16	-0.04
	Non-CPP	-0.02	-0.04	-0.03	-0.04	-0.02	-0.04
	Weekend	n/a	0.00	n/a	0.00	n/a	0.00
X	CPP	-0.10	-0.03	-0.05	-0.02	-0.37	-0.03
	Non-CPP	-0.04	-0.02	-0.05	-0.02	-0.04	-0.02
	Weekend	n/a	-0.06	n/a	-0.06	n/a	-0.06

The elasticities of substitution for the residential CPP-V tariff (with technology) were derived from data for treatment and control customers on the CPP-V rate in the SPP. As discussed in the Summer 2003 SPP report, these customers are not representative of the population as a whole because they were selected from customers that had previously volunteered for the AB970 Smart Thermostat pilot and because they represent households in a single service territory and climate zone (SDG&E Inland zone) with central air conditioning. Nevertheless, we believe they still represent the best source of estimates for households with enabling technology. The underlying demand model from which the elasticity of substitution estimates were derived has an interaction term between price and weather and, therefore, allows us to tailor the estimates to PG&E's climate zones.

We assumed that the elasticity of substitution for households on a CPP-V rate who do not choose an enabling technology is the same as for households on the CPP-F rate. In addition, we also assumed that the daily elasticity estimates for households on a CPP-V rate both with and without technology is the same as for households on the CPP-F rate without technology. This assumption was made because of the unreasonably high daily price elasticity estimates obtained from the SPP analysis for CPP-V customers with technology, which were roughly 10 times larger than for households on the CPP-F rate without technology. The magnitude of this difference produced extremely large impact estimates that were deemed to be unrealistic.

The Monte Carlo simulations are based on a probability distribution of elasticity values. The low and high end elasticities and elasticities of substitution used in the Monte Carlo analysis were based largely on the distribution of values reported in Table 5-8 of the Summer 2003 SPP report. This table shows how elasticities vary with differences in customer characteristics. In addition to the variation there, we also calculated elasticities based on weather extremes using data and models discussed in Section 5.1.2 of the SPP report. We selected the high and low extreme values from the range of estimates for each zone. Finally, the percentage change from the base value for the high and low end estimates was applied to the PG&E base values in Table 8 to produce the low and high end estimates reported in Table 9. In order to simplify the analysis, the Monte Carlo simulations only varied the elasticity of substitution and daily price elasticity values on CPP days. Given the very small contribution of changes in demand and energy-use on non-CPP days to the total benefit calculation, relaxing this simplifying assumption would have very little impact on the range of estimates used in the analysis.

Table 9
Range of CPP-Day Elasticity Estimates For Residential Customers Used in the Monte Carlo Simulations

Climate Zone	Scenario	CPP-F		TOU		CPP Tech Enabled	
		Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity
R	High	-0.18	-0.10	-0.14	-0.06	-0.52	-0.10
	Low	-0.10	0	-0.08	0	-0.25	0
S	High	-0.17	-0.16	-0.12	-0.08	-0.50	-0.16
	Low	-0.08	0	-0.06	0	-0.24	0
T	High	-0.10	-0.11	-0.06	-0.10	-0.17	-0.11
	Low	-0.02	0	-0.01	0	-0.08	0
X	High	-0.15	-0.11	-0.08	-0.07	-0.39	-0.11
	Low	-0.07	0	-0.04	0	-0.19	0

D2b. Small Commercial and Industrial Elasticities

As reported in the Summer 2003 SPP report, the small C&I elasticities estimated from the SPP data for Summer 2003 are not appropriate for application to most rate options, as they are based on a special sample of small C&I customers that had previously volunteered for the AB970 Smart Thermostat pilot in SCE's service territory. Thus, we conducted a literature review to determine if more suitable values were available that would be more representative of the general small C&I population.

The literature on this subject for the small C&I population is quite limited. Four potentially relevant studies were found, two from California (PG&E and SCE), one from Ontario and one from Israel.[8]

The SCE study was based on experimental data from the early 1980s for customers with demands less than 500 kW.

- Six tariffs were examined, 3 with TOU demand charges and flat energy charges, and 3 with TOU energy charges and no demand charges;
- The summer peak period was from noon to 6 pm and the price ratios ranged from about 1.3:1 to about 2.4:1;
- Results were reported for 3 size strata (0 to 50 kW, 50 to 200 kW and 200 to 500 kW);
- The elasticity of substitution was positive and significant for the 0 to 50 kW strata, negative and significant with a value of -.074 for the 50 to 200 kW strata, and positive and insignificant for the largest strata;
- A positive elasticity of substitution is not economically rational in this instance.

The PG&E study was based on experimental data collected in 1982.

- Three 3-period TOU rates were examined with peak-off-peak price ratios equal to 8:1, 4:1 and 1.9:1. The peak period was from 12:30 to 6:30 pm;
- The peak-period, partial own price elasticity was around –0.03;
- When combined with an assumed daily price elasticity (these were not estimated in the study) equal to –0.05, a 2:1 TOU price produced a reduction in peak-period energy use equal to 2.4 percent;

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8 D.J.Aigner and J. G. Hirschberg, "Commercial/industrial customer response to time-of-use electricity prices: some experimental results," Rand Journal of Economics, Vol. 16, No. 3, Autumn 1985.

D.J. Aigner, J. Newman and A. Tishler, "The Response of Small and Medium-size Business Customers to Time-of-Use Electricity Rates in Israel," Journal of Applied Econometrics, Volume 9, 1994.

J.C. Ham, D.C. Mounta in and M.W.L. Chan, "Time-of-Use Prices and Electricity Demand: Allowing for Selection Bias in Experimental Data," Rand Journal of Economics Vol. 28, No. 0, 1997.

Chi-Keung Woo, "Demand for Electricity of Small Nonresidential Customers Under Time-Of-Use Pricing," The Energy Journal, Vol. 6, No. 4, 1985.

- This study reported a range in estimates of the daily price elasticity (taken from a 1981 review by Bohi) from –0.05 to –0.20.

The Israeli study found no statistically significant price elasticities in the summer period.

The Ontario study was based on data from a pricing experiment conducted in 1986 and 1987.

- The sample consisted of only 120 customers with demands below 50 kW, 90 of which were placed on one of three experimental rates;
- Three TOU rates were tested where both the price ratio and length of the peak period varied;
    - A 9 hour peak period with a 4.5:1 price ratio
    - A 16 hour peak period with a 3:1 price ratio
    - A 5 hour peak period (from 2 to 7 pm) with a 6:1 price ratio
- The only statistically significant results were for the 5-hour rate treatment but, importantly, the elasticity was not significant for customers with "electric water heating and air conditioning;"
- Given the high saturations of electric water heating and space heating and the relative low saturations of air conditioning in Ontario, we do not believe this study is of much relevance to the population of California businesses.

Of the studies summarized above, CRA believes the PG&E study is the most relevant and defensible.

- The SCE study results were quite mixed and, in the author's own words, in some cases were "clearly anomalous."
- The Israeli and Ontario studies are based on populations and conditions quite different from those of California.
- The PG&E peak period is nearly the same as for the rates we are examining here and the price ratios used in the study, which range from roughly 2:1 to 8:1, are comparable to those being examined here.

Given the above, we used the price simulation model for the CES specification to replicate the PG&E study impact estimate that shows a peak-period reduction of 2.5% for a 2:1 price ratio. An elasticity of substitution equal to –0.06 combined with a daily price elasticity equal to –0.05 (the low end of the range reported by Bohi) produces a peak-period reduction comparable to the PG&E result. These values, reported in Table 10, were used for the TOU and CPP-F analysis.

Estimates of the elasticity of substitution on CPP days for the CPP-V analysis with technology were based on the CPP-V model estimated from the SPP data. The same daily elasticity that was developed above was used for the CPP-V analysis, rather than the estimate developed in the SPP, as it is thought to be more representative of the general population on non-CPP days when the technology does not contribute to demand response.

Table 10
Small C&I Base Case Price Elasticity Estimates

Day Type	TOU and CPP-F		CPP Tech Enabled	
	Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity
CPP	-0.06	-0.05	-0.15	-0.05
Non-CPP	-0.06	-0.05	-0.06	-0.05
Weekend	0	0	0	0

The range in elasticity estimates for the CPP-day elasticities underlying the Monte Carlo analysis for the small C&I segment was assumed to be the same, in percentage terms, as for residential customers. The low and high-end estimates are reported in Table 11. As with the residential analysis, we did not examine the range of impacts resulting from variation in elasticities on non-CPP days elasticities, as these have little impact on the overall value of capacity and energy benefits.

Table 11
Range Of CPP-Day Elasticity Estimates For Small C&I Customers
Used in the Monte Carlo Simulations

Scenario	TOU and CPP-F		CPP Tech Enabled	
	Elasticity of Substitution	Daily Price Elasticity	Elasticity of Substitution	Daily Price Elasticity
High	-0.09	-0.17	-0.16	-0.17
Low	-0.04	0	-0.08	0

D3. Prices

The prices used in this analysis are seasonally revenue neutral compared with current rates for each customer segment. Modeling was performed for customers that are currently on the following PG&E rates: E-1, A-1, A-6, A-10 (Non-TOU), and E-19-Voluntary. For each rate, seasonally revenue neutral tariffs were developed for TOU, CPP-F and CPP-P rates. Prices for the CPP-V tariff are assumed to be the same as for the CPP-F tariff.

Generally speaking, it is assumed that the new rates have approximately the same characteristics and complexities as do PG&E's existing rates. That is, the new, time-varying rates are "layered on top of" the existing rates. PG&E's existing rates have the following characteristics:

- **Residential (E-1):** An inverted tiered rate with four tiers with baseline quantities that vary across climate zones.

- **Schedule A-1, Small General Service:** A two-part tariff (fixed and variable components) with seasonally differentiated prices for energy. There are no demand charges for this tariff.

- **Schedule A-6, Small General Time-of-Use Service:** A two-part tariff with energy charges that vary by time of day and season. There are three rate periods for energy in the summer (e.g. Peak, Part-Peak, and Off-Peak) and two in the winter (e.g. Part-Peak and Off-Peak). There are no demand charges for this tariff.

- **Schedule A-10 (Non-TOU), Medium General Demand-Metered Service:** A two-part tariff with seasonally differentiated energy prices. There is a demand charge (e.g. maximum monthly demand) that varies by season.

- **Schedule E-19-Voluntary, Medium General Demand-Metered Time-of-Use Service:** A two-part tariff with energy charges that vary by time of day and season. There are demand charges (e.g. maximum peak demand, maximum part-peak demand, and maximum demand). The maximum demand charges apply to maximum demand whenever it occurs and the peak and part-peak demand charges apply to maximum demand during the peak and part-peak periods, respectively. If the overall maximum demand occurs during either the peak or part-peak period, the two demand charges are additive.

In order to accurately reflect existing and alternate average prices, it is necessary to model all components of the customer bills. For example, for customers on the E-1 rate, it is necessary to factor in the credits and surcharges associated with each tier. For customers on the A-10 and E-19 Schedules above, it is necessary to capture demand charges in average energy charges. Thus, in modeling A-10 customers, the maximum monthly demand charge was included in average price calculations for all rate periods. Correspondingly, the maximum demand charge for E-19 customers was included in average price calculations for all rate periods. However, the maximum peak demand and part-peak demand charges were included in average price calculations only for their respective rate periods (on both CPP and non-CPP days). PG&E provided the estimates for average billing demand shown in Table 12 below.

Table 12
Billing Demand

Season	Tariff Schedule	Demand	Zone			
			T	X	S	R
Summer	A-10	Monthly	49.36	60.87	60.12	58.86
	E-19	Monthly	55.17	60.33	63.38	63.02
		Peak	52.43	59.28	60.87	59.38
		Part-Peak	54.08	60.33	63.38	63.02

D4. Participation Rates

Participation rate estimates for the residential sector are based largely on results of research performed by Momentum Market Intelligence (MMI) in conjunction with the SPP.[9] The MMI research involved a complex conjoint survey and analysis that estimated customer preferences for rates structurally similar to those tested in the SPP as well as extensions of the SPP rates such as a pure CPP rate. The MMI estimates take into consideration customer inertia, customer risk tolerance and awareness of rate options. Key findings from the MMI research include the following:

- Under the assumption of reasonable awareness (e.g., 50 to 70 percent of customers are aware of the choices available), between 15 and 24 percent of customers would select one of the time-varying rate options on an opt-in basis.

- The MMI model predicts little variation in participation rates across the various rate options on an opt-in or opt-out basis, including little difference between a CPP-F and pure CPP rates or between CPP-F and CPP-V rates, with the following caveat. All participation rates are subject to adjustment based on the target population. Thus, for example, if a CPP-V rate is only available to customers with central air conditioning and the saturation of air conditioning is, say 50 percent, then an 80 percent participation estimate for the eligible population would result in a 40 percent participation for the CPP-V rate (e.g., 0.8 x 0.5 = 0.4) for the population as a whole.

- Roughly 80 percent of customers will stay with their existing rate, regardless of the type or number of alternatives offered, given an assumption of 50 percent awareness of alternatives and moderate savings from switching.

- If the CPP-F tariff is the default option and both a TOU and the pre-existing rate are offered as options, about 80 percent of customers would stay with the default CPP-F rate, roughly 5 percent would move to the TOU rate and about 15 percent would move to the standard rate.

- With a very high level of awareness of alternative options (e.g., 100 percent awareness), roughly 60 percent of customers will stay on the default rate and with low awareness (e.g., around 30 percent), about 90 percent of customers will stay on the default rate.

Using the above findings as a guide, the following general rules were applied in developing the participation rate estimates for the base case:

- The participation rate for all default rate options is assumed to be 80 percent.

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[9] Momentum Market Intelligence. *Customer Preferences Market Research (CPMR): A Market Assessment of Time-Differentiated Rates Among Residential Customers in California.* December 2003.

- The participation rate for all opt-in rates relative to the current rate as a default is 20 percent.

- If a new rate is offered on an opt-out basis, 20 percent will select one of the alternative options. As suggested by the MMI research, out of this group, 15 percent would select the previously existing tariff and 5 percent would select the other new tariff, if both are available.

- For customers on each rate, only those with central air conditioning are offered enabling technology. Any customer is allowed to go on a CPP-V rate for example, but only households with central air conditioning can select the technology option. This rule leads to different participation levels for technology-enabled options for the partial and full-deployment scenarios because the saturation of air conditioning varies across these scenarios.

- Participation rates for technology options were modeled as if customers first choose to opt-in or stay on (in the case of opt-out rates) a rate independent of any decision related to technology and, once on a rate, some eligible customers will examine and accept the technology option.

- To determine the number of eligible households on a rate that will accept the technology option, we assumed that only households who are "active shoppers" will consider the technology. For rates that are offered on an opt-in basis, we assume that all customers who select the rate option are "active shoppers" and, thus, will also consider the technology option if they are eligible for it (i.e., if they have air conditioning). Of those who consider the technology and are eligible for it, the percent that take the technology is assumed to be 50 percent. Thus, for example, for an opt-in CPP-V rate with technology offered for the full deployment scenario, we assume that 20 percent will take the rate. Of these, the 37.8 percent that have air conditioning and, therefore are eligible for the technology, will consider the technology, but only 50 percent will take it. Thus, the participation shares for this opt-in rate offering are as follows: 20 percent take the CPP-V rate; roughly 4 percent take the technology ($.04 \cong .0379 = 0.2 \times 0.379 \times 0.5$); 16 percent ($.16 = 0.2 - 0.04$) will be on the rate without the technology; and 80 percent of customers will stay on the current rate.

- When a rate with a technology option is offered on a default basis, the following rules apply. As with all rates, it is assumed that roughly 80 percent of the population will stay on the default rate. However, it is further assumed that the majority of these customers stay on the rate due largely to inertia rather than due to an active consideration of all other options. As above, we assume that only "active shoppers" consider the technology option. We further assume that, of the 80 percent who will stay on the rate, only 20 percent are active shoppers (just as for the opt-in case). Given this assumption, the percent of all customers who go on the rate and accept the technology option will be the same as for an opt-in program. Thus, the final percent participation numbers for this default scenario are as follows: 80 percent of customers will stay on the default CPP-V rate, of which 4 percent will accept the technology and 76 percent will not.

- When constructing the low and high participation estimates, we assumed that the default participation level would equal 60 percent rather than 80 percent for the low-end estimate, and would equal 90 percent for the high-end estimate. These estimates roughly correspond to the estimated participation rates based on the MMI analysis when customer awareness of alternative options equals 100 percent and 30 percent, respectively.

Tables 13 through 15 summarize the logic underlying the participation estimates for the technology options for the low and high participation rate scenarios for residential customers. Tables 16 and 17 summarize nominal and effective prices. Tables 18 through 20 summarize participation estimates for all residential scenarios. The columns labeled TOU, CPP-F, CPP-V etc. represent the CEM runs from which the various ACR scenarios are constructed. The CPP-F model runs are used to represent both the CPP-F and CPP-V tariff for customers without technology and the CPP-V model runs represent both tariffs for customers with technology. The columns labeled CPP-P and CPP-PT represent, respectively, the pure CPP rate without and with enabling technology. The numbers containing in the column labeled ACR Scenario correspond to the numbers contained in the table on page 9 of the main body of this submission.

Table 13
Calculation of Participation Rates for Residential Customers
(Base Case Participation Rate Scenarios)

Deployment	% of AMI Customers who Remain on Default Rate and Do Not Consider Technology	% of AMI Customers who Choose Rate and Consider Technology	% Eligible for Tech (Have CAC)	% of (b) who would Choose Tech if Eligible	% of AMI Customers on CPP-F Rate with Tech	% of AMI Customers on CPP-F Rate without Technology	% of AMI Customers on TOU/Current Rate without Technology
	(a)	(b)	(c)	(d)	(e)=(b)*(c)*(d)	(f)=(b)-(e)+(a)	(g)=100%-(e)-(f)
Default = CPP-F							
Optional = TOU/Current							
Partial	60.0%	20.0%	63.4%	50.0%	6.3%	73.7%	20.0%
Full	60.0%	20.0%	37.9%	50.0%	3.8%	76.2%	20.0%
Default = Current							
Optional = CPP-F							
Partial	60.0%	20.0%	63.4%	50.0%	6.3%	13.7%	80.0%
Full	60.0%	20.0%	37.9%	50.0%	3.8%	16.2%	80.0%

Table 14
Calculation of Participation Rates for Residential Customers
(High Participation Rate Scenarios)

Deployment	% of AMI Customers who Remain on Default Rate and Do Not Consider Technology	% of AMI Customers who Choose Rate and Consider Technology	% Eligible for Tech (Have CAC)	% of (b) who would Choose Tech if Eligible	% of AMI Customers on CPP-F Rate with Tech	% of AMI Customers on CPP-F Rate without Technology	% of AMI Customers on TOU/Current Rate without Technology
	(a)	(b)	(c)	(d)	(e)=(b)*(c)*(d)	(f)=(b)-(e)+(a)	(g)=100%-(e)-(f)
Default = CPP-F							
Optional = TOU/Current							
Partial	60.0%	30.0%	63.4%	50.0%	9.5%	80.5%	10.0%
Full	60.0%	30.0%	37.9%	50.0%	5.7%	84.3%	10.0%
Default = Current							
Optional = CPP-F							
Partial	60.0%	30.0%	63.4%	50.0%	9.5%	20.5%	70.0%
Full	60.0%	30.0%	37.9%	50.0%	5.7%	24.3%	70.0%

Table 15
Calculation of Participation Rates for Residential Customers
(Low Participation Rate Scenarios)

Deployment	% of AMI Customers who Remain on Default Rate and Do Not Consider Technology	% of AMI Customers who Choose Rate and Consider Technology	% Eligible for Tech (Have CAC)	% of (b) who would Choose Tech if Eligible	% of AMI Customers on CPP-F Rate with Tech	% of AMI Customers on CPP-F Rate without Technology	% of AMI Customers on TOU/Current Rate without Technology
	(a)	(b)	(c)	(d)	(e)=(b)*(c)*(d)	(f)=(b)-(e)+(a)	(g)=100%-(e)-(f)
Default = CPP-F							
Optional = TOU/Current							
Partial	50.0%	10.0%	63.4%	50.0%	3.2%	56.8%	40.0%
Full	50.0%	10.0%	37.9%	50.0%	1.9%	58.1%	40.0%
Default = Current							
Optional = CPP-F							
Partial	50.0%	5.0%	63.4%	50.0%	1.6%	3.4%	95.0%
Full	50.0%	5.0%	37.9%	50.0%	0.9%	4.1%	95.0%

Table 16
Nominal and Effective Prices Residential Customers

Rate	Day Type	Effective Rates (cents/kWh)		Nominal Rates (cents/kWh)	
		Peak	Off-Peak	Peak	Off-Peak
Current	All	13.3	13.3	11.6	11.6
TOU	Weekdays	20.7	11.8	19.9	9.9
CPP-F and CPP-V	CPP	70.3	10.6	75.0	8.6
	Non-CPP	18.4	10.6	17.2	8.6
CPP-P	CPP	70.3	11.7	75.0	9.9
	Non-CPP	11.7	11.7	9.9	9.9

Table 17
Nominal and Effective Prices For Small C&I Customers

Rate	Day Type	Price (cents/kWh)	A1		A6		A10		E19V	
			Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Current	All	Nominal	14.9	14.9	23.3	5.6	8.9	8.9	7.5	4.9
		Effective	18.6	18.6	27.7	8.2	16.6	16.6	28.0	9.3
TOU	Weekdays	Nominal	23.8	11.9	n/a	n/a	14.0	7.0	n/a	n/a
		Effective	26.6	15.9	n/a	n/a	21.7	14.7	n/a	n/a
CPP-F And CPP-V	CPP	Nominal	75.0	10.5	75.0	7.3	75.0	5.2	75.0	3.1
		Effective	72.7	14.6	74.3	9.8	82.7	13.0	95.5	7.5
	Non-CPP	Nominal	20.9	10.5	14.6	7.3	10.5	5.2	6.1	3.1
		Effective	24.0	14.6	19.9	9.8	18.2	13.0	26.6	7.5
CPP-P	CPP	Nominal	75.0	12.8	75.0	9.0	75.0	6.5	75.0	3.7
		Effective	72.7	16.7	74.3	11.2	82.7	14.2	95.5	8.1
	Non-CPP	Nominal	12.8	12.8	9.0	9.0	6.5	6.5	3.7	3.7
		Effective	16.7	16.7	14.8	11.2	14.2	14.2	24.1	8.1

Table 18
Participation Rates for ACR Scenarios for the Residential Market Segment
(Base Case Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	Current	None	n/a	n/a						100%	100%
2	Current	None	Partial	n/a						100%	100%
3	Current	None	Partial	n/a						100%	100%
4	Current	None	Full	n/a						100%	100%
5	Current	None	Full	n/a						100%	100%
6	TOU	Current or CPP-F	Partial	N	80%	5%				15%	100%
7	TOU	Current or CPP-F	Full	N	80%	5%				15%	100%
8	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Partial	N	5%	80%				15%	100%
9	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Full	N	5%	80%				15%	100%
10	CPP-F-T (Res) or CPP-V (C&I)	Current or TOU	Full	Y	5%	76%	4%			15%	100%
11	Current	CPP-P	Partial	N				20%		80%	100%
12	Current	CPP-P-T	Partial	Y				14%	6%	80%	100%
13	Current	CPP-P	Full	N				20%		80%	100%
14	Current	CPP-P-T	Full	Y				16%	4%	80%	100%
15	Current	CPP-F or CPP-V	Partial	N		20%				80%	100%
16	Current	CPP-F or CPP-V	Partial	Y		14%	6%			80%	100%
17	Current	CPP-F or CPP-V	Full	N		20%				80%	100%
18	CPP-P	Current	Partial	N				80%		20%	100%
19	CPP-P	Current	Full	N				80%		20%	100%

Table 19
Participation Rates for ACR Scenarios for the Residential Market Segment
(Low Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	**Current**	**None**	**n/a**	**n/a**						100%	100%
2	**Current**	**None**	**Partial**	**n/a**						100%	100%
3	**Current**	**None**	**Partial**	**n/a**						100%	100%
4	**Current**	**None**	**Full**	**n/a**						100%	100%
5	**Current**	**None**	**Full**	**n/a**						100%	100%
6	**TOU**	**Current or CPP-F**	**Partial**	**N**	60%	0%				40%	100%
7	**TOU**	**Current or CPP-F**	**Full**	**N**	60%	0%				40%	100%
8	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Partial**	**N**	0%	60%				40%	100%
9	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**N**	0%	60%				40%	100%
10	**CPP-F-T (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**Y**	0%	58%	2%			40%	100%
11	**Current**	**CPP-P**	**Partial**	**N**				5%		95%	100%
12	**Current**	**CPP-P-T**	**Partial**	**Y**				3%	2%	95%	100%
13	**Current**	**CPP-P**	**Full**	**N**				5%		95%	100%
14	**Current**	**CPP-P-T**	**Full**	**Y**				4%	1%	95%	100%
15	**Current**	**CPP-F or CPP-V**	**Partial**	**N**		5%				95%	100%
16	**Current**	**CPP-F or CPP-V**	**Partial**	**Y**		3%	2%			95%	100%
17	**Current**	**CPP-F or CPP-V**	**Full**	**N**		5%				95%	100%
18	**CPP-P**	**Current**	**Partial**	**N**				60%		40%	100%
19	**CPP-P**	**Current**	**Full**	**N**				60%		40%	100%

Table 20
Participation Rates for ACR Scenarios for the Residential Market Segment
(High Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
ACR Scenario	**Default Tariff**	**Other Tariffs**	**Deployment**	**Technology**						100%	100%
1	**Current**	**None**	**n/a**	**n/a**						100%	100%
2	**Current**	**None**	**Partial**	**n/a**						100%	100%
3	**Current**	**None**	**Partial**	**n/a**						100%	100%
4	**Current**	**None**	**Full**	**n/a**						100%	100%
5	**Current**	**None**	**Full**	**n/a**	90%	5%				5%	100%
6	**TOU**	**Current or CPP-F**	**Partial**	**N**	90%	5%				5%	100%
7	**TOU**	**Current or CPP-F**	**Full**	**N**	5%	90%				5%	100%
8	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Partial**	**N**	5%	90%				5%	100%
9	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**N**	5%	84%	6%			5%	100%
10	**CPP-F-T (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**Y**				30%		70%	100%
11	**Current**	**CPP-P**	**Partial**	**N**				20%	10%	70%	100%
12	**Current**	**CPP-P-T**	**Partial**	**Y**				30%		70%	100%
13	**Current**	**CPP-P**	**Full**	**N**				24%	6%	70%	100%
14	**Current**	**CPP-P-T**	**Full**	**Y**		30%				70%	100%
15	**Current**	**CPP-F or CPP-V**	**Partial**	**N**		20%	10%			70%	100%
16	**Current**	**CPP-F or CPP-V**	**Partial**	**Y**		30%				70%	100%
17	**Current**	**CPP-F or CPP-V**	**Full**	**N**				90%		10%	100%
18	**CPP-P**	**Current**	**Partial**	**N**				90%		10%	100%
19	**CPP-P**	**Current**	**Full**	**N**				90%		10%	100%

Tables 21 through 26 summarize the participation estimates for the small C&I customers for the low and high participation rate assumptions. MMI also performed survey research among small C&I customers to determine preferences for alternative rate options and the results were similar to those for the residential sector.[10] As such, the same basic rules outlined above for the residential sector were used to develop participation rates for the small C&I customers. One key difference between the residential and small C&I scenarios is the assumption that 100 percent of the total small C&I population has central air conditioning and, therefore, is eligible for enabling technology.

[10] Momentum Market Intelligence. *Customer Preferences Market Research (CPMR)-C&I: A Market Assessment of Time-Differentiated Rates Among C&I Customers in California.* July 2003.

Table 21
Participation Rates for ACR Scenarios for A1 and A10 C&I Customers
(Base Case Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	Current	None	n/a	n/a						100%	100%
2	Current	None	Partial	n/a						100%	100%
3	Current	None	Partial	n/a						100%	100%
4	Current	None	Full	n/a						100%	100%
5	Current	None	Full	n/a						100%	100%
6	TOU	Current or CPP-F	Partial	N	78%	2%				20%	100%
7	TOU	Current or CPP-F	Full	N	78%	2%				20%	100%
8	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Partial	N	20%	20%	20%			40%	100%
9	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Full	N	20%	20%	20%			40%	100%
10	CPP-F-T (Res) or CPP-V (C&I)	Current or TOU	Full	Y	20%	20%	20%			40%	100%
11	Current	CPP-P	Partial	N				20%		80%	100%
12	Current	CPP-P-T	Partial	Y				10%	10%	80%	100%
13	Current	CPP-P	Full	N				20%		80%	100%
14	Current	CPP-P-T	Full	Y				10%	10%	80%	100%
15	Current	CPP-F or CPP-V	Partial	N		10%	10%			80%	100%
16	Current	CPP-F or CPP-V	Partial	Y		10%	10%			80%	100%
17	Current	CPP-F or CPP-V	Full	N		10%	10%			80%	100%
18	CPP-P	Current	Partial	N				80%		20%	100%
19	CPP-P	Current	Full	N				80%		20%	100%

Table 22
Participation Rates for ACR Scenarios for A1 and A10 C&I Customers
(Low Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	Current	None	n/a	n/a						100%	100%
2	Current	None	Partial	n/a						100%	100%
3	Current	None	Partial	n/a						100%	100%
4	Current	None	Full	n/a						100%	100%
5	Current	None	Full	n/a						100%	100%
6	TOU	Current or CPP-F	Partial	N	60%	2%				38%	100%
7	TOU	Current or CPP-F	Full	N	60%	2%				38%	100%
8	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Partial	N	5%	5%	5%			85%	100%
9	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Full	N	5%	5%	5%			85%	100%
10	CPP-F-T (Res) or CPP-V (C&I)	Current or TOU	Full	Y	5%	5%	5%			85%	100%
11	Current	CPP-P	Partial	N				5%		95%	100%
12	Current	CPP-P-T	Partial	Y				5%	5%	90%	100%
13	Current	CPP-P	Full	N				5%		95%	100%
14	Current	CPP-P-T	Full	Y				5%	5%	90%	100%
15	Current	CPP-F or CPP-V	Partial	N		5%	5%			90%	100%
16	Current	CPP-F or CPP-V	Partial	Y		5%	5%			90%	100%
17	Current	CPP-F or CPP-V	Full	N		5%	5%			90%	100%
18	CPP-P	Current	Partial	N				60%		40%	100%
19	CPP-P	Current	Full	N				60%		40%	100%

Table 23
Participation Rates for ACR Scenarios for A1 and A10 C&I Customers
(High Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	**Current**	**None**	**n/a**	**n/a**						100%	100%
2	**Current**	**None**	**Partial**	**n/a**						100%	100%
3	**Current**	**None**	**Partial**	**n/a**						100%	100%
4	**Current**	**None**	**Full**	**n/a**						100%	100%
5	**Current**	**None**	**Full**	**n/a**						100%	100%
6	**TOU**	**Current or CPP-F**	**Partial**	**N**	90%	2%				8%	100%
7	**TOU**	**Current or CPP-F**	**Full**	**N**	90%	2%				8%	100%
8	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Partial**	**N**	30%	30%	30%			10%	100%
9	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**N**	30%	30%	30%			10%	100%
10	**CPP-F-T (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**Y**	30%	30%	30%			10%	100%
11	**Current**	**CPP-P**	**Partial**	**N**				30%		70%	100%
12	**Current**	**CPP-P-T**	**Partial**	**Y**				15%	15%	70%	100%
13	**Current**	**CPP-P**	**Full**	**N**				30%		70%	100%
14	**Current**	**CPP-P-T**	**Full**	**Y**				15%	15%	70%	100%
15	**Current**	**CPP-F or CPP-V**	**Partial**	**N**		15%	15%			70%	100%
16	**Current**	**CPP-F or CPP-V**	**Partial**	**Y**		15%	15%			70%	100%
17	**Current**	**CPP-F or CPP-V**	**Full**	**N**		15%	15%			70%	100%
18	**CPP-P**	**Current**	**Partial**	**N**				90%		10%	100%
19	**CPP-P**	**Current**	**Full**	**N**				90%		10%	100%

Table 24
Participation Rates for ACR Scenarios for A6 and E19V C&I Customers
(Base Case Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	Current	None	n/a	n/a						100%	100%
2	Current	None	Partial	n/a						100%	100%
3	Current	None	Partial	n/a						100%	100%
4	Current	None	Full	n/a						100%	100%
5	Current	None	Full	n/a						100%	100%
6	TOU	Current or CPP-F	Partial	N	0%	10%				90%	100%
7	TOU	Current or CPP-F	Full	N	0%	10%				90%	100%
8	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Partial	N	0%	20%	30%			50%	100%
9	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Full	N	0%	20%	30%			50%	100%
10	CPP-F-T (Res) or CPP-V (C&I)	Current or TOU	Full	Y	0%	20%	30%			50%	100%
11	Current	CPP-P	Partial	N				20%		80%	100%
12	Current	CPP-P-T	Partial	Y				10%	10%	80%	100%
13	Current	CPP-P	Full	N				20%		80%	100%
14	Current	CPP-P-T	Full	Y				10%	10%	80%	100%
15	Current	CPP-F or CPP-V	Partial	N		10%	10%			80%	100%
16	Current	CPP-F or CPP-V	Partial	Y		10%	10%			80%	100%
17	Current	CPP-F or CPP-V	Full	N		10%	10%			80%	100%
18	CPP-P	Current	Partial	N				80%		20%	100%
19	CPP-P	Current	Full	N				80%		20%	100%

Table 25
Participation Rates for ACR Scenarios for A6 and E19V C&I Customers
(Low Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	**Current**	**None**	**n/a**	**n/a**						100%	100%
2	**Current**	**None**	**Partial**	**n/a**						100%	100%
3	**Current**	**None**	**Partial**	**n/a**						100%	100%
4	**Current**	**None**	**Full**	**n/a**						100%	100%
5	**Current**	**None**	**Full**	**n/a**						100%	100%
6	**TOU**	**Current or CPP-F**	**Partial**	**N**	0%	5%				95%	100%
7	**TOU**	**Current or CPP-F**	**Full**	**N**	0%	5%				95%	100%
8	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Partial**	**N**	0%	5%	10%			85%	100%
9	**CPP-F (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**N**	0%	5%	10%			85%	100%
10	**CPP-F-T (Res) or CPP-V (C&I)**	**Current or TOU**	**Full**	**Y**	0%	5%	10%			85%	100%
11	**Current**	**CPP-P**	**Partial**	**N**				5%		95%	100%
12	**Current**	**CPP-P-T**	**Partial**	**Y**				5%	5%	90%	100%
13	**Current**	**CPP-P**	**Full**	**N**				5%		95%	100%
14	**Current**	**CPP-P-T**	**Full**	**Y**				5%	5%	90%	100%
15	**Current**	**CPP-F or CPP-V**	**Partial**	**N**		5%	5%			90%	100%
16	**Current**	**CPP-F or CPP-V**	**Partial**	**Y**		5%	5%			90%	100%
17	**Current**	**CPP-F or CPP-V**	**Full**	**N**		5%	5%			90%	100%
18	**CPP-P**	**Current**	**Partial**	**N**				60%		40%	100%
19	**CPP-P**	**Current**	**Full**	**N**				60%		40%	100%

Table 26
Participation Rates for ACR Scenarios for A6 and E19V C&I Customers
(High Participation Rate Scenarios)

ACR Scenario	Default Tariff	Other Tariffs	Deployment	Technology	TOU	CPP-F	CPP-V	CPP-P	CPP-PT	Current	Sum
1	Current	None	n/a	n/a						100%	100%
2	Current	None	Partial	n/a						100%	100%
3	Current	None	Partial	n/a						100%	100%
4	Current	None	Full	n/a						100%	100%
5	Current	None	Full	n/a						100%	100%
6	TOU	Current or CPP-F	Partial	N	0%	10%				90%	100%
7	TOU	Current or CPP-F	Full	N	0%	10%				90%	100%
8	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Partial	N	0%	30%	40%			30%	100%
9	CPP-F (Res) or CPP-V (C&I)	Current or TOU	Full	N	0%	30%	40%			30%	100%
10	CPP-F-T (Res) or CPP-V (C&I)	Current or TOU	Full	Y	0%	30%	40%			30%	100%
11	Current	CPP-P	Partial	N				30%		70%	100%
12	Current	CPP-P-T	Partial	Y				15%	15%	70%	100%
13	Current	CPP-P	Full	N				30%		70%	100%
14	Current	CPP-P-T	Full	Y				15%	15%	70%	100%
15	Current	CPP-F or CPP-V	Partial	N		15%	15%			70%	100%
16	Current	CPP-F or CPP-V	Partial	Y		15%	15%			70%	100%
17	Current	CPP-F or CPP-V	Full	N		15%	15%			70%	100%
18	CPP-P	Current	Partial	N				90%		10%	100%
19	CPP-P	Current	Full	N				90%		10%	100%

D5. Additional Variables

In addition to the key input variables discussed above, CRA's CEM requires input on the following variables:

- Meter deployment rates
- The number of customers by rate class
- Growth in the number of customers
- Avoided capacity and energy costs by rate period
- Generation reserve margins
- Line loss factor
- The discount rate used to calculate the net present value of benefits.

The values used for each of these variables are discussed below.

Estimates for the rate of deployment of AMI meters by month were developed by PG&E and are discussed in Appendix A. The monthly deployment rates were converted by CRA to the annual average values used in the CEM by converting the monthly installation of meters during the deployment phase into annual average values using the average number of months each meter was installed. For example, if a meter was installed in January, it received a weight of 12/12 = 1—if it was installed in December, it received a weight of 1/12. Since the vast majority of benefits occur during the summer, this approach overstates the benefits associated with meters installed in the second half of the year. On the other hand, the meters installed in February, March and April are discounted in their contribution to the average calculation because any meter placed prior to the hot days of summer should contribute maximum benefits for that year, not, for example, 9/12 of a contribution. The average annual deployment rates used for both the partial and full deployment scenarios are shown in Table 27.

Table 27
Cumulative Deployment By Climate Zone and Year
(%)

Year	T	X	S	R
2006	1	1	18	1
2007	2	6	89	52
2008	13	66	100	100
2009	76	99	100	100
2010	100	100	100	100

Table 28 summarizes the assumed values for the number of customers in the starting year for each market segment and climate zone. Table 29 summarizes the average annual growth in customers.

Table 28
Number of Customers
(2003)

Climate Zone	Residential	A-1	A-6	A-10	E-19-V
T	1,087,310	97,157	7,165	11,939	2,075
X	1,622,801	138,320	9,383	21,899	2,466
S	821,986	80,142	5,154	9,028	1,148
R	700,206	67,471	5,514	8,837	1,354

Table 29
Annual Percent Growth in Number of Customers

Climate Zone	Residential	A-1	A-6	A-10	E-19-V
T	1.00	1.27	1.27	1.27	1.27
X	1.03	1.17	1.17	1.17	1.17
S	2.22	1.42	1.42	1.42	1.42
R	1.86	1.54	1.54	1.54	1.54

PG&E used an avoided cost of capacity of $85/kW-yr. This value is held constant over the forecast horizon.

The avoided cost of energy on critical peak days is $70/MWh. This cost is also held constant. No guidance was provided in the ACR for energy costs during other rate periods. These values would have a very small impact on the total avoided capacity and energy benefits. Nevertheless, they are required as input to the CEM. For the current filing, CRA developed estimates based on data publicly available a couple of years ago. These values are summarized in Table 30.

Table 30
Avoided Energy Cost: Baseline Scenario with Critical Peak Period ($/kWh) (Summer)

Year	Peak Period CPP Days	Peak Period Non-CPP Days	Partial-Peak CPP Days	Partial-Peak Non-CPP Days	Off-Peak CPP Days	Off-Peak Non-CPP Days	Off-Peak Weekend
2005	0.0700	0.0471	0.0417	0.0417	0.0417	0.0417	0.0417
2006	0.0700	0.0466	0.0413	0.0413	0.0413	0.0413	0.0413
2007	0.0700	0.0462	0.0409	0.0409	0.0409	0.0409	0.0409
2008	0.0700	0.0457	0.0405	0.0405	0.0405	0.0405	0.0405
2009	0.0700	0.0468	0.0415	0.0415	0.0415	0.0415	0.0415
2010	0.0700	0.0480	0.0425	0.0425	0.0425	0.0425	0.0425
2011	0.0700	0.0491	0.0435	0.0435	0.0435	0.0435	0.0435
2012	0.0700	0.0503	0.0446	0.0446	0.0446	0.0446	0.0446
2013	0.0700	0.0515	0.0456	0.0456	0.0456	0.0456	0.0456
2014	0.0700	0.0527	0.0467	0.0467	0.0467	0.0467	0.0467
2015	0.0700	0.0540	0.0478	0.0478	0.0478	0.0478	0.0478
2016	0.0700	0.0553	0.0490	0.0490	0.0490	0.0490	0.0490
2017	0.0700	0.0566	0.0501	0.0501	0.0501	0.0501	0.0501
2018	0.0700	0.0579	0.0513	0.0513	0.0513	0.0513	0.0513
2019	0.0700	0.0593	0.0525	0.0525	0.0525	0.0525	0.0525
2020	0.0700	0.0606	0.0537	0.0537	0.0537	0.0537	0.0537
2021	0.0700	0.0621	0.0550	0.0550	0.0550	0.0550	0.0550

The discount rate used in the analysis is 7.70 percent.[11] Line losses are assumed to equal 10.86 percent and the reserve margin is assumed to equal 15 percent.

[11] The costs and operational benefits reported in Appendix B and elsewhere in this submission were based on a discount rate of 7.41 percent. The 7.7 percent value used here will understate slightly the overall net benefits reported elsewhere.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing U 39 E	Rulemaking 02-06-001 (filed June 6, 2002)

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) FOR PROTECTIVE ORDER

CONFIDENTIAL MATERIAL ATTACHED AND FILED UNDER SEAL, NAMELY, APPENDIX B - CASE RESULTS (CASES B1-B19) TO PRELIMINARY AMI BUSINESS CASE ANALYSIS OF PACIFIC GAS AND ELECTRIC COMPANY

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October 15, 2004

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing U 39 E	Rulemaking 02-06-001 (filed June 6, 2002)

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY
(U 39-E) FOR PROTECTIVE ORDER

Pursuant to Rule 42 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), Pacific Gas and Electric Company (PG&E) hereby moves the Commission for issuance of a protective order, in the form attached, to protect certain confidential cost-related information being filed today in this docket.

The purpose of the protective order is to ensure that potential vendors in PG&E's recently issued Request For Proposals (RFP) related to Advanced Metering Infrastructure (AMI) do not obtain PG&E's preliminary cost estimates of installing AMI or direct load control technology.

BACKGROUND

On July 21, 2004 the Assigned Commissioner in this proceeding issued a Ruling directing the utilities to file their preliminary business cases for AMI deployment by October 15, 2004. Accordingly, PG&E is filing its preliminary business case analysis today (Business Case Filing). This analysis contains a detailed breakdown of PG&E's current estimates of the costs of AMI deployment, including AMI meters, an AMI meter reading network and related infrastructure and services. The parts of PG&E's filing specifying that information are being filed with the Commission under seal, and PG&E is requesting that this material be accorded confidential treatment under section 583 of the California Public Utilities Code. PG&E has served redacted versions of the confidential material on the service list.

On June 2, 2004 the Administrative Law Judge in this proceeding issued a Ruling requiring the utilities to file by October 15, 2004 their proposed demand response programs for 2005. Accordingly, today PG&E is filing its demand response proposals for implementation in Summer 2005 and beyond (Demand Response Program Filing). One of the programs PG&E is proposing is an air conditioning (A/C) cycling program commencing in 2005. The filing contains PG&E's initial estimates of the costs of installing this technology. The parts of PG&E's filing specifying that information have been filed with the Commission under seal, and PG&E is requesting that this material be accorded confidential treatment under section 583 of the Public Utilities Code. PG&E has served redacted versions of the confidential material on the service list.

On September 27, 2004 PG&E issued an RFP seeking bids for installation of an AMI system, and related products and services. The RFP also seeks proposals for A/C cycling to be installed in PG&E's service territory next summer, and for longer-term deployment in conjunction with AMI. Responses to the RFP are due on November 10, 2004. Thereafter PG&E expects to embark on a process of selecting promising proposals for further review and possible negotiation of contracts.

PROPOSED PROTECTIVE ORDER

PG&E believes that is would be detrimental to its RFP process if potential vendors obtain information on PG&E's cost estimates of the products and services vendors may bid on in response to the RFP. The integrity of the RFP and subsequent negotiation process requires that bidders not be privy to PG&E's internal evaluations of AMI or direct load control technology. Access to such information could provide vendors with information that could lead them to bidder higher prices than they would bid without knowing the utility's cost estimates.

Accordingly, PG&E proposes that vendors not be allowed to obtain un-redacted versions of the Business Case Filing or the Demand Response Program Filing, or of any underlying work-papers. Accordingly, PG&E seeks adoption of a protective order, in the form attached, which would prevent such access by vendors.

Vendors would include all entities that received PG&E's RFP, or who (in PG&E's judgment) could be involved with the supply of AMI products and services to PG&E, and their, affiliates, subcontractors and consultants. All individuals wishing to review the un-redacted filings would be required to execute a non-disclosure certificate agreeing to the terms of the protective order. CPUC staff and CEC staff would be exempt from these requirements but would be required to treat the information confidentially. PG&E will keep records of all non-disclosure certificates and persons and entities entitled to review the un-redacted filings. If PG&E learns, at any time during the bid process and prior to execution of any contracts, that a bidder involved in PG&E's RFP process had access to the confidential cost information in PG&E's filings, this fact may be grounds for action by PG&E, including disqualification of the bidder, if PG&E determines in its sole discretion that its bid process, or its results, were detrimentally affected in a material way.

CONCLUSION

For the foregoing reasons, PG&E urges the Commission to adopt the attached protective order.

Respectfully Submitted,

LINDA L. AGERTER
PETER OUBORG

By:______________________________________
PETER OUBORG

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 15, 2004

ATTACHMENT

PROPOSED PROTECTIVE ORDER

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing	Rulemaking 02-06-001

**PROTECTIVE ORDER REGARDING
CONFIDENTIALITY OF ADVANCED METERING
INFRASTRUCTURE (AMI) AND DIRECT LOAD
CONTROL-RELATED COST INFORMATION**

1. This Protective Order shall govern access to and the use of all Protected Materials of Pacific Gas and Electric Company (PG&E) in this proceeding as hereinafter defined. Notwithstanding any order terminating this docket, this Protective Order shall remain in effect until, after notice and an opportunity to be heard, it is specifically modified or terminated by the Assigned Commissioner, the Assigned Administrative Law Judge ("Assigned ALJ"), the law and Motion Administrative Law Judge ("Law and Motion ALJ") or the California Public Utilities Commission ("CPUC" or "Commission"). This Protective Order does not address the right of employees of the Commission (hereinafter "Commission Staff") acting in their official capacities to view Protected Materials, since Commission Staff review of such Protected Materials is governed by the requirements of Section 583 of the Public Utilities Code and the Commission's General Order 66-C. This Protective Order imposes certain restrictions on employees of the California Energy Commission ("CEC") who request to review Protected Material in the course of their official duties.

2. **Definitions –**

a. The term "**AMI**" shall mean Advanced Metering Infrastructure as that term is used in Docket R. 02-06-001.

b. The term "**AMI Products and Services**" shall mean the AMI-related products and services (including the component parts thereof) for which PG&E is seeking bids in its RFP, including direct load control systems to be deployed in PG&E's service territory in 2005 and beyond as described in the RFP.

c. The term "**RFP**" means the request for proposals for AMI Products and Services issued on September 27, 2004 by PG&E.

d. The term "**redacted**" refers to situations in which confidential or proprietary information in a document, whether the document is in paper or electronic form, has been covered, masked or blocked out. The term "**un-redacted**" refers to situations in which confidential or proprietary information in a document, whether in paper or electronic form, has not been covered, masked or blocked out.

e. The term "**Protected Materials**" means the confidential or proprietary information contained in the unredacted version, and not contained in the redacted version, of any of the following: PG&E's October 15, 2004 "Preliminary AMI Business Case Analysis," including all attachments and appendices, filed in R. 02-06-001 ("Business Case Filing"); PG&E's October 15, 2004 "Proposal of Pacific Gas and Electric Company Concerning Working Group 2 Programs And Related Issues," including all attachments and appendices, filed in R. 02-06-001 ("Demand Response Program Filing"); and work-papers prepared by PG&E in connection with the Business Case Filing and the Demand Response Program Filing.

f. “**Protected Materials**” shall also include: (A) any information contained in or obtained from the unreadacted materials described in the preceding paragraph; (B) any other materials that are made subject to this Protective Order by any assigned ALJ, Law and Motion ALJ, or Assigned Commissioner, or by the CPUC or any court or other body having appropriate authority; (C) notes of Protected Materials; and (D) copies of Protected Materials. PG&E and Commission Staff, when creating any Protected Materials, shall physically mark such materials on each page (or in the case of non-documentary materials such as computer diskettes, on each item) as “PROTECTED MATERIALS”, or with words of similar import as long as one or more of the terms, “Protected Materials,” “Confidential,” “Section 583” or “General Order No. 66-C” is included in the designation to indicate that the materials in question are Protected Materials.

g. The term “**Notes of Protected Materials**” means memoranda, handwritten notes, or any other form of information (including information in electronic form) that copies or discloses materials described in Paragraph 2 (f). Except as specifically provided otherwise in this Order, notes of Protected Materials are subject to the same restrictions as are Protected Materials.

h. **Protected Materials** shall not include: (A) any information or document contained in the public files of the CPUC or any other state or federal agency, or in any state or federal court, unless such information or document has been determined to be protected by such agency or court; or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order.

i. The term “**Non-Disclosure Certificate**” shall mean the certificate annexed hereto as Appendix A by which persons shall be granted access to the Protected Materials. Such persons shall, as a condition of such access, certify their understanding that such access is provided pursuant to the terms and restrictions of this Protective Order, and that such persons have read such Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be sent to and retained by PG&E.

j. The term **Non-Vendor Participating Party** (“NVPP”) shall mean an entity that is not a Vendor Participating Party (as defined below); and an NVPP Reviewing Representative shall mean a person who is:

1. Not a VPP Reviewing Representative under paragraph 2(k) as determined by PG&E. NVPPs shall identify their proposed Reviewing Representatives to PG&E. Upon request by PG&E, NVPPs shall provide a curriculum vitae of the candidate, including a brief description of the candidate’s professional experience and past and present professional affiliations for the last 10 years. PG&E shall advise the proposing party in writing within three (3) business days from receipt of the notice if PG&E objects to the proposed Reviewing Representative, setting forth in detail the reasons therefore. In the event of such objection, the proposing party and PG&E shall promptly meet and confer to try to resolve the issue, and if necessary seek a ruling from either the assigned

ALJ or the Law and Motion ALJ. In addition to determining whether the proposed Reviewing Representative has a need to know, the ALJ in ruling on the issue will evaluate whether the candidate is engaged in the activities related to submitting bids or negotiation of contracts related to PG&E's RFP (or the direct supervision of any employee(s) whose duties include such activities) or consulting on such matters (or the direct supervision of any employee(s) whose duties include such consulting). Absent unusual circumstances as determined by the ALJ, a candidate who falls within the criteria set forth in the preceding sentence will ordinarily be deemed ineligible to serve as an NVPP Reviewing Representative

2. An employee of: (A) a state governmental agency other than the California Energy Commission (CEC) that (i) is not a Vendor Participating Party as defined in Paragraph 2(k) hereof, and (ii) is statutorily authorized to obtain access to confidential data held by another state governmental agency upon execution of a written agreement to treat the data so obtained as confidential, as provided in Government Code Section 6254.5 (e); or (b) any other consumer or customer group that PG&E, and the Assigned ALJ or Assigned Commissioner, agree has a bona fide interest in participating on behalf of end-use customers in Rulemaking R. 02-06-001, regarding PG&E, and which group is not a Vendor Participating

Party as defined in paragraph 2(k);

3. An attorney, paralegal, consultant or employee of a consultant retained by an NVPP for the purpose of advising, preparing for or participating in Docket R.02-06-001.

k. The term **Vendor Participating Party** ("VPP") shall mean an entity that engages in the supply of AMI Products and Services, or an association comprised of entities that engage in such activities, and any affiliate of such an entity or association; and a "VPP Reviewing Representative" shall mean a person who is:

1. An employee of or independent contractor engaged by a VPP; or
2. An attorney, consultant or other advisor (or any employee or independent contractor engaged by the same) of a VPP.

3. Access of NVPP Reviewing Representatives to Protected Materials shall be granted only pursuant to the terms of this Protective Order. Participants in this proceeding who are designated as VPP Reviewing Representatives shall not be granted access to Protected Material, but shall instead be limited to reviewing redacted versions of documents that contain Protected Materials.

4. Whenever PG&E submits a document in this proceeding that includes data PG&E contends is confidential or proprietary, PG&E shall also prepare a redacted version of such document. The redacted version shall be sufficiently detailed in organization so that persons familiar with this proceeding (including VPP Reviewing Representatives) can determine with reasonable certainty the nature (but not magnitude) of the data that has been redacted. The redacted version of any document required by this paragraph shall be served on all persons on

the service list (or, in the case of discovery, on all persons entitled to the discovery responses) who are not entitled to obtain access to Protected Materials hereunder. All disputes regarding redacted versions of documents shall be submitted for resolution to the CPUC in accordance with Paragraph 11 of this Protective Order.

5. a) CEC staff who are required to review Protected Materials in the course of their official duties may do so provided the CEC treats the requested Protected Materials as confidential in accordance with Paragraphs 7 and 9 of this Protective Order and to the same degree as required of the CPUC pursuant to the provisions of Public Utilities Code section 583. CEC staff are not required to execute a Non-Disclosure Certificate. The CPUC shall retain sole authority (subject to judicial review) to make the determination whether the Protected Materials should remain confidential or be disclosed to the public, notwithstanding any provision to the contrary in the statutes or regulations applicable to the CEC.

b) In the event the CPUC receives a request for a copy of or access to Protected Materials from a state governmental agency other than the CEC that is authorized to enter into a written agreement sufficient to satisfy the requirements for maintaining confidentiality set forth in Government Code Section 6254.5 (e), the CPUC may, after giving written notice to PG&E of the request, release such Protected Materials to the requesting governmental agency, upon receiving from the requesting agency a written commitment to treat the requested Protected Materials in the same manner as required of the CEC in Paragraph 5 (a) above.

6. If a request is made pursuant to the Public Records Act (PRA), Government Code §6250, et seq., that the Protected Materials filed with or otherwise in the possession of the CPUC be produced, the CPUC will notify PG&E of the PRA request and will notify the requester that the Protected Materials are public records that fall within the exclusions listed in Section 2 of the

General Order No. 66(c), and/or that there is a public interest served by withholding the records. See paragraphs 2.2 and 3.3 of General Order No. 66-C. In the event the CPUC receives a request from a federal government agency or via a judicial subpoena for the production of Protected Materials in the CPUC's possession, the CPUC will also notify PG&E of such request. In the event that a PRA requester brings suit to compel disclosure of Protected Materials in the CPUC's possession, the CPUC will also notify PG&E of such request. In the event that a PRA requester brings suit to compel disclosure of Protected Materials, Commission Staff and PG&E shall cooperate in opposing the suit.

7. Protected Materials shall be treated as confidential by each NVPP Reviewing Representative in accordance with the certificate executed pursuant to Paragraphs 2(i) and 9 hereof. Protected Materials shall not be used except as necessary for the conduct of this proceeding, and shall not be disclosed in any manner to any person except (i) other NVPP Reviewing Representatives who are engaged in this proceeding and need to know the information in order to carry out their responsibilities, and (ii) persons employed by or working on behalf of the CEC or other state governmental agencies covered by Paragraphs 5(a) and 5(b). In the event a NVPP not covered by 5(a) and (b) above is requested or required by applicable laws or regulations, or in the course of administrative or judicial proceedings (in response to oral questions, interrogatories, request for information or documents, subpoena, civil investigative demand or similar process) to disclose any Protected Materials, the NVPP agrees to oppose disclosure on the grounds that the requested information has already been designated by the Commission as Protected Materials subject to this Protective Order lawfully issued by the Commission and therefore may not be disclosed. The NVPP shall also immediately inform PG&E of the request, and PG&E may, at its sole discretion and cost, direct any challenge or

defense against the disclosure requirement, and the NVPP shall cooperate with PG&E to the maximum extent practicable to either oppose the disclosure of the Protected Materials consistent with applicable law, or obtain confidential treatment of Protected Materials by the entity that wishes to receive the Protected Materials prior to any such disclosure.

8. It shall be a rebuttable presumption that (i) any study that incorporates, describes or otherwise employs Protected Materials in a manner that could reveal all of a part of the Protected Materials, or (ii) any model that relies upon Protected Materials for algorithms or other computation(s) critical to the functioning of the model, shall also be considered Protected Materials subject to Section 583 of the Public Utilities Code, the Commission's General Order 66-C, and this Protective Order. However, models that merely use Protected Materials as inputs will not themselves be considered Protective Materials. It shall also be a rebuttable presumption that where the inputs to studies or models include Protected Materials, or where the outputs of such studies or models reveal such inputs or can be processed to reveal the Protected Materials, such inputs and/or outputs shall be considered Protected Materials subject to this Protective Order, unless such inputs and/or outputs have been redacted or aggregated to the satisfaction of PG&E. Unless a party, by means of notice and motion, obtains a ruling from the Assigned ALJ or the Law and Motion ALJ holding that the applicable presumption(s) from among the foregoing has been rebutted with respect to the model or study at issue, then any party who devises or propounds a model or study that incorporates, uses or is based upon Protected Materials shall label the model or study "Protected Materials," and it shall be subject to the terms of this Protective Order.

9. No NVPP Reviewing Representative shall be permitted to inspect, participate in discussions regarding, or otherwise be granted access to Protected Materials pursuant to this

Protective Order unless such NVPP Reviewing Representative has first executed a Non-Disclosure Certificate and delivered it to PG&E. Upon request, PG&E shall provide copies of executed Non-Disclosure Certificates to Commission Staff. Attorneys qualified as NVPP Reviewing Representatives shall ensure that persons under their supervision or control comply with this Protective Order.

10. In the event that an NVPP Reviewing Representative to whom Protected Materials are disclosed ceases to be engaged in proceedings in this docket related to the Business Case Filing or the Demand Response Program Filing, or is employed or retained for a position with an employer not qualified to be an NVPP, then access to Protected Materials by that person shall be terminated. Even if no longer engaged in such proceedings, every such person shall continue to be bound by the provisions of this Protective Order and the Non-Disclosure Certificate.

11. All disputes arising under this Protective Order shall be presented for resolution to the Assigned ALJ or the Law and Motion ALJ. Prior to presenting any such dispute to the applicable ALJ, the parties to the dispute shall use their best efforts to resolve it. Neither PG&E nor the Commission Staff waives its right to seek additional administrative or judicial remedies after the Assigned ALJ or the law and Motion ALJ has made a ruling regarding the dispute.

12. All documents containing Protected Materials that are filed with the Commission or served shall be placed in sealed envelopes or otherwise appropriately protected and shall be endorsed to the effect that they are filed or served under seal pursuant to this Protective Order. Such documents shall be marked with the words "**PROTECTED MATERIALS**" or one of the other, similar terms set forth in paragraph 2(f) hereof, and shall be served upon all NVPP Reviewing Representatives and persons employed by or working on behalf of the state

governmental agencies referred to in Paragraphs 5(a) and 5(b) who are eligible to see the Protected Materials. Service upon the persons specified in the foregoing sentence shall be by electronic mail in accordance with the electronic Service Protocols adopted in this docket. The Assigned ALJ shall be served with such documents by hand on the date that service is due.

13. Nothing in this Protective Order shall be construed as limiting the right of PG&E, Commission Staff, an NVPP or a state governmental agency covered by Paragraph 5(a) or 5(b) from objecting to the use of Protected Materials on any legal ground, such as a relevance or privilege.

14. All Protected Materials filed with judicial or administrative bodies other than the Commission, whether in support of or as part of a motion, brief or other document or pleading, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials that are subject to this Protective Order.

15. Neither PG&E nor the Commission Staff waives its right to pursue any other legal or equitable remedy that may be available in the event of actual or anticipated disclosure of Protected Materials.

16. PG&E and Commission Staff may agree at any time to remove the “Protected Material” designation from any material if, in their mutual opinion, its confidentiality is no longer required. In such a case, PG&E will notify all parties that PG&E believes are in possession of such materials of the change of designation.

Dated October _____, 2004, at San Francisco, California.

/s/

Administrative Law Judge

APPENDIX A

PAGE 1

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing U 39 E	Rulemaking 02-06-001 (filed June 6, 2002}

NON-DISCLOSURE CERTIFICATE

I, ____________________, have been asked by ___________ to inspect certain materials that have been designated as "Protected Materials" under Paragraph 2 of the Protective Order entered in the above-captioned matter by the Administrative Law Judge's Ruling Adopting Protective Order dated ________, 2004 (the "Order").

1. I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Order in this proceeding, that I have been given a copy of and have read the Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with the Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the California Public Utilities Commission.

2. I understand that my review of Protected Materials is solely for the purpose of participating in the above-captioned matter, and that any other use or disclosure of Protected Materials by me is a violation of the Order.

3. I hereby agree to submit to the exclusive jurisdiction of the California Public Utilities Commission for the enforcement of the undertakings I have made hereby and I waive any objection to venue laid with the Commission for enforcement of the Order

Dated:

BY: ___________________________________

TITLE: _________________________________

REPRESENTING:________________________

CERTIFICATE OF SERVICE BY MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, PO Box 770000, B8R, San Francisco, CA 94120.

I am readily familiar with the electronic service protocols set forth in Appendix A attached to the Order Instituting Rulemaking issued June 6, 2002 in Docket R.02-06-001.

On October 15, 2004, I served a true copy of:

PRELIMINARY AMI BUSINESS CASE ANALYSIS AND

MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) FOR PROTECTIVE ORDER

either by e-mail or by placing it for collection and mailing, in the course of ordinary business practice, with other correspondence of Pacific Gas and Electric Company, enclosed in a sealed envelope, with postage fully prepaid, addressed to:

All parties to Rulemaking 02-06-001

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on October 15, 2004.

SYLVIA D. GARDNER