March 15, 2005

VIA HAND DELIVERY

Docket Office
State of California Public Utilities Commission
505 Van Ness Avenue, Room 2001
San Francisco, CA 94102

Re: Pacific Gas and Electric Company
Rulemaking 02-06-001

Dear Sir/Madam:

Enclosed for filing are an original and five copies of **UPDATED PRELIMINARY AMI BUSINESS CASE ANALYSIS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E)**. PG&E is filing its business case analysis under seal and is also filing, concurrently with this pleading, a motion for leave to file under seal. Please place a file-stamped copy of this filing in the PG&E box for pick up. Thank you.

Very truly yours,

Peter Ouborg

PO:ka

Enclosures

cc: CPUC Commissioner Michael R. Peevey
CEC Commissioner Art Rosenfeld
ALJ Michelle Cooke
Julie Fitch
Moises Chavez
Bruce Kaneshiro
David Hungerford
Mike Messenger
Service List (redacted version)

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)

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

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Dated: March 15, 2005

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BEFORE THE PUBLIC UTILITIES COMMISSION
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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)

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

Pursuant to the November 11, 2004 "Assigned Commissioner and Administrative Law Judge's Ruling Calling For A Technical Conference To Begin Development Of A Reference Design And Delaying Filing Date Of Utility Advanced Metering Infrastructure Applications," (ACR) Pacific Gas and Electric Company (PG&E) presents in this filing an update to PG&E's October 15, 2004 preliminary business case analysis of Advanced Metering Infrastructure (AMI) deployment.[1]

Overall, as this filing demonstrates, PG&E believes it is very close to constructing a viable, cost-effective business case for full deployment of AMI to all of its customers. This update is not PG&E's final AMI business case, however, because PG&E has not completed vendor and technology selection. PG&E intends to file its full AMI Project application, with

[1] This filing consists of a summary pleading that generally describes the analysis, recommendations, and next steps and five appendices providing additional detail. The appendices are: Appendix A, System Map; Appendix B, Full Deployment Scenario Analysis; Appendix C, Partial Deployment Scenario Analysis; Appendix D, Demand Response Analysis; and Appendix E, Preliminary Analysis of Initial Residential Rate Design Alternatives. Both the pleading and the appendices contain certain AMI cost and implementation information that should be withheld from vendors while PG&E completes vendor selection and negotiates final AMI contracts. Accordingly, PG&E is filing an unredacted version of this pleading with the Commission under seal, together with a motion to file under seal. Redacted versions are being served on the service list in this proceeding. PG&E will provide unredacted versions of this filing to regulatory staff and to entities who have executed PG&E's non-disclosure agreement consistent with the ALJ's November 2, 2004 ruling. Workpapers supporting PG&E's analysis will be made available upon request.

specific technology and project costs, in summer 2005 and to commence setting meters in the first quarter of 2006, if the Commission grants approval for cost recovery of the AMI Project. PG&E's goal is to be able to begin offering dynamic electric pricing options to customers in the summer of 2006. This ambitious goal is achievable, but depends on the Commission expeditiously processing both PG&E's AMI Project Pre-deployment Application, being filed today, seeking cost recovery for pre-deployment activities, and PG&E's full AMI deployment application. PG&E is excited at the prospect of finally delivering AMI's multiple benefits to PG&E's customers, and looks forward to meeting and overcoming the implementation challenges that lie ahead.

I. EXECUTIVE SUMMARY

A. Summary Of Results And Key Changes In Business Case Analysis

After extensive cost and benefit analysis, PG&E is pleased to present, in this update filing, major improvements to the AMI business case filed on October 15, 2004. The most important development is that PG&E's updated analysis shows that AMI can largely be justified by the operational benefits and savings to the utility and is no longer heavily dependent on obtaining a high level of demand response benefits. The operational "gap" between the costs and benefits for a full AMI deployment case (PG&E's preferred deployment strategy) has shrunk dramatically -- from $1,162 million to $ 409 million on a present value revenue requirement (PVRR) basis. Thus, about 79 percent of the costs of the project would be covered by expected savings in utility costs. At this level, AMI is potentially cost effective under certain opt-in demand response scenarios.

A net present value of about $400 million in electric demand response benefits (valuing demand response at $85/kW-year) would result if one in four of PG&E's residential customers reduced peak demand on average by 0.29 kWh/hr on critical peak pricing (CPP) event days (maximum of 15 days per year). Examples of customer actions that would produce this level of load drop include turning up the thermostat control on a central air conditioner from 72 degrees to 78 degrees during the CPP pricing event or shifting operation of a swimming pool pump out of the CPP hours. Of course, additional demand response should be achievable by small and medium-sized commercial customers. It seems reasonable to expect that the Commission will be able to develop electric demand response programs with AMI that could achieve this level of benefits or better.

Key aspects of the analysis that have changed since October 15 include:

- Responses to PG&E's September 2004 Request for Proposals (RFP) indicate cost improvement in nearly every aspect of the project, including meter modules, network equipment, information technology (IT) systems requirements, and operations and maintenance (O&M).
- Closer analysis of how AMI will affect operations yielded an additional $37 million per year in projected benefits above the $96 million estimated in the October 15 filing, for a total of $133 million. Some of this increase represents inclusion of electric accounts with demands greater than 200 kW (excluded on October 15), yielding additional benefits due to less expensive data communication costs.
- Critical Peak Pricing (CPP) event notification is now based on outbound dialing to each participant rather than mass media messages.
- PG&E refined its demand response benefits analysis especially of the "opt-in" scenarios.

The following two charts show how this update analysis has narrowed the gap between costs and operational benefits, and shows how opt-in demand response program scenarios are now in the general range of the new operational gap:

Chart 1: Illustration of Improvement in PG&E'S Business Case (Full Deployment)

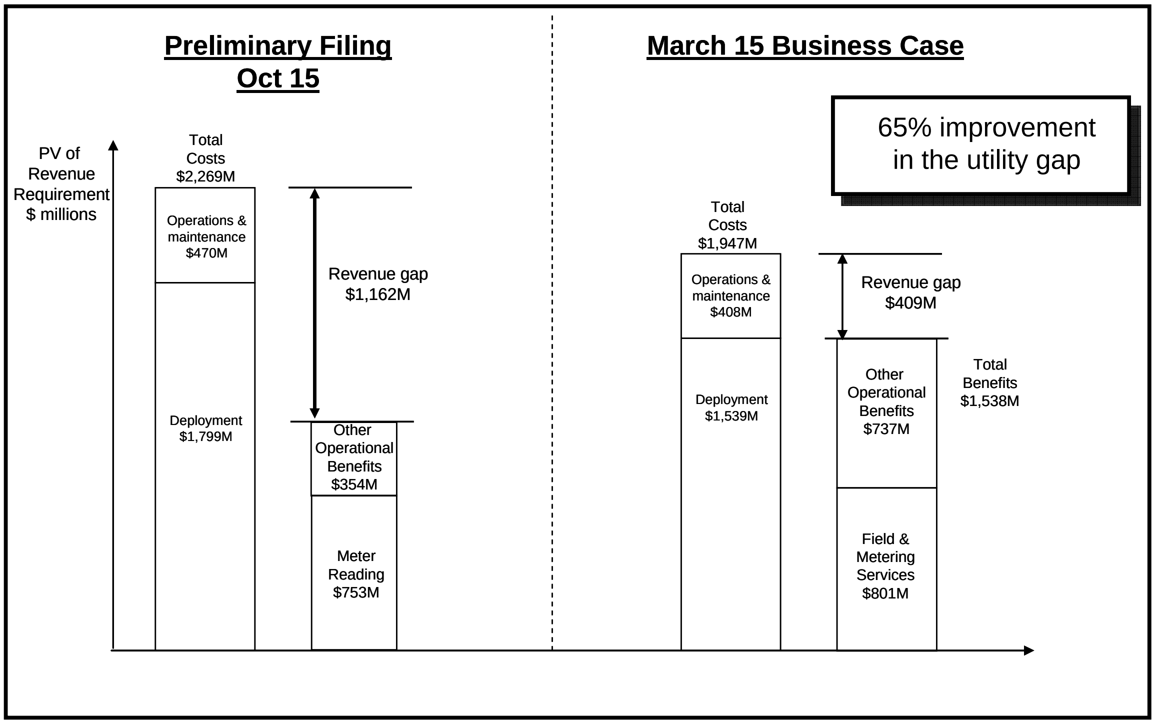
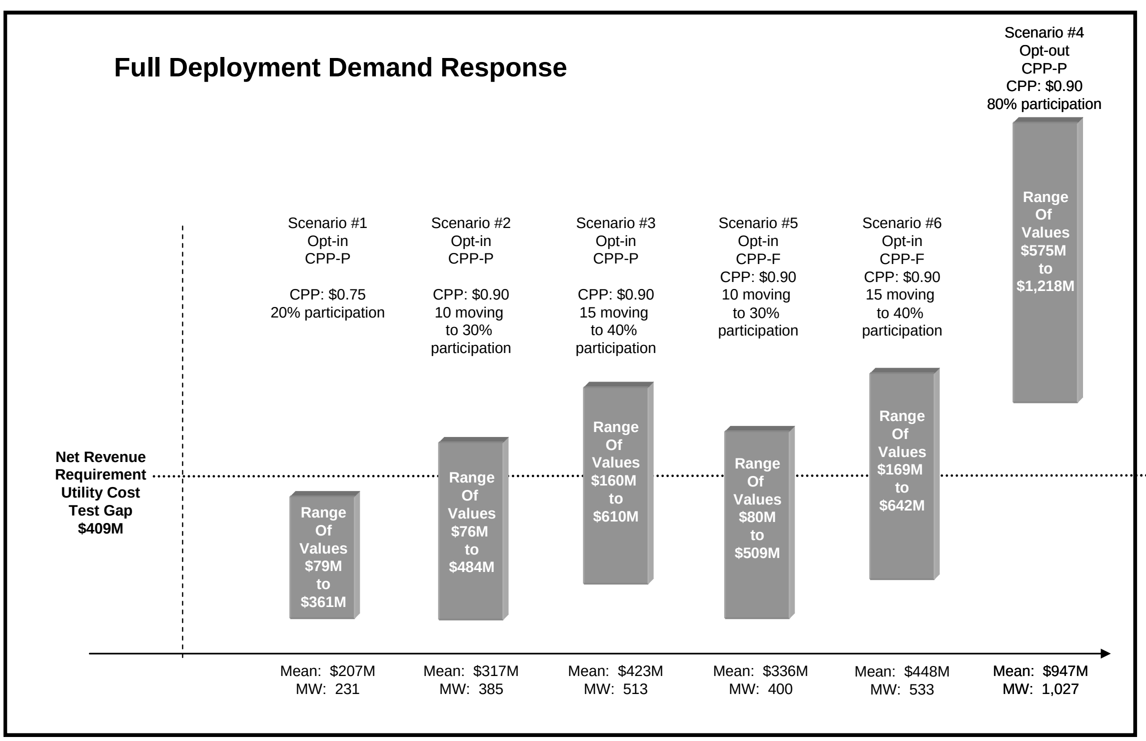


Chart 2: Comparison of Full Deployment Operational Gap To Various Demand Response Scenarios



Despite the progress in refining costs and benefits, these results are still subject to further change as PG&E moves through final bid selection and refines its benefits analysis. The gap between costs and benefits may narrow further as a result of vendor selection and negotiation, and identification of new operational benefits. On the other hand, this gap may increase for a variety of reasons including identification of new costs, and changes in key regulatory and financing assumptions (see Section VIII below). Similarly, demand response benefits are subject to change if the key assumptions change. For example, demand response benefits will decrease if capacity is valued at less than $85/kW-yr. On the other hand, different demand response program designs adopted by the Commission in the future could increase the magnitude of demand response benefits shown.

PG&E proposes full deployment as its preferred option since full deployment will yield the maximum value of operational savings and the maximum value of demand response benefits possible, over time. The operational "gap" between costs and savings is greater for the partial deployment case than for the full deployment case. The partial case has far fewer customers with advanced meters able to provide the demand response benefits to close that gap. Additionally, full deployment allocates the fixed costs of AMI (incurred for any type of deployment) over the most meters.

More important, however, it is critical that PG&E's entire utility business, and all of its customers, not merely some subset, share in the benefits of AMI technology. AMI is a tool that will transform both regulatory policy and utility business operations. For this reason it should be deployed throughout PG&E's service territory.

Overall, this update analysis shows that the AMI project is potentially viable under a variety of assumptions. PG&E has not yet chosen a final AMI technology, but remains optimistic that continued work with vendors will yield a cost-effective AMI project that PG&E can bring before the Commission in its AMI Project Application, anticipated in the summer of 2005.

B. Update On PG&E's RFP Process And PG&E's Anticipated Timeline For AMI Project Application

On September 27, 2004, PG&E issued an RFP to potential vendors for both an AMI system and a load control system. On November 10, 2004 PG&E received approximately 40 supplier proposals in response to the RFP (including a total of 77 separate bids on the various sub-components of the RFP). Over the past 4 months, PG&E's bid review team has conducted an intensive process to narrow the bids down to a "short list." This process, which has included multiple series of all day meetings with vendors to clarify their bids, has considered factors such as price, functionality, performance, vendor maturity, business terms, product maturity, schedule, and overall risk.

The short list vendors will soon be asked to submit "best and final" offers (BAFO) on a limited number of implementation scenarios currently being developed by PG&E. Following submission of BAFOs, PG&E will select its finalists and negotiate contracts, a process expected to be completed in summer 2005.

C. Pre-Deployment Cost Recovery Request

In a separate Application filed today, PG&E has requested cost recovery for certain pre-deployment costs in order to continue with critical path activities of the AMI Project while PG&E completes vendor negotiations, develops its AMI Project Application for full deployment costs and moves through the regulatory process. There are two distinct phases of the AMI Project: "pre-deployment" and "deployment." PG&E's preliminary project plan for AMI deployment shows meter installation beginning in the first quarter of 2006. To meet that deployment schedule, the pre-deployment phase must begin in the summer of 2005. The two phases are described below:

- The “pre-deployment” phase includes those activities required to prepare for a mass meter installation. It includes development of systems necessary to accomplish the meter changes and advance testing of certain IT system elements, including: (1) an AMI Master System controller(s) which will monitor the AMI system to ensure full system operability; and (2) an AMI Interface System which translates the raw interval meter reads into discrete accessible data formats for use in subsequent IT systems such as the billing system, the outage information system, fixed asset records, and customer information. The pre-deployment funding also supports an end-to-end system acceptance test of about 5,000 meters to ensure both the installations processes and computer systems are ready for full scale deployment.
- The “deployment” phase includes procuring and installing all meter sets, network elements, and the additional system changes required to achieve full operational benefits, including comprehensive outage management and customer access to data. The deployment phase will begin after PG&E’s Board of Directors reviews and approves the capital spending and the Commission approves cost recovery for the AMI Project.

Concurrently with the AMI Project Application, PG&E also intends to file its initial proposal for dynamic electric rates to be implemented along with AMI deployment. It is PG&E’s hope that it will have the capability to provide in the summer of 2006 dynamic electric rate options to the first groups of customers with AMI meters installed. To achieve this goal, the Commission will need to adopt dynamic electric rate tariffs no later than January 2006 to allow for timely programming, testing and implementation of the rates.

The proposed timeline is summarized below:

TABLE 1: PROPOSED TIMELINE FOR REGULATORY APPROVAL AND IMPLEMENTATION PG&E'S AMI PROJECT

Activity	Date
Business case update and AMI Pre-deployment Application filed	March 15, 2005
BAFO process and contract negotiation	March – Summer 2005
AMI Project Application filed	Summer, 2005
Application for approval of dynamic rates for residential and small commercial customers	Summer, 2005
Pre-deployment cost recovery granted	July 1, 2005
Pre-deployment phase of AMI Project	Begins July 2005
Large-scale deployment of meters begins	First quarter, 2006
Dynamic rates offered to customers with AMI meters	Summer, 2006

D. Summary of Rate Impacts and Cost Recovery Proposals

1. Illustrative rate impacts

PG&E projects that the overall net rate impacts of a full deployment AMI Project will be less than 1% of PG&E's total electric and gas annual revenue requirements. However, since the required electric revenues would not necessarily be allocated equally across all customer classes, and (given AB 1X constraints) cannot be allocated equally to all residential electric usage, the electric rate impacts for some individual customers or customer groups may be somewhat greater than 1 percent.

Based on revenue requirements models, the peak year for recovery of AMI-related net capital and operating costs would be 2009 for the full deployment case. The combined monthly bill impact under full deployment for a customer with average gas and electric use would be about $0.82. The monthly bill impact for a typical customer with relatively high gas and electric use would be about $2.95. This bill impact is based on the operational gap in the year 2009, which is the peak year of revenue recovery for the full deployment case. It does not include procurement savings attributable to demand response, or bill impacts attributable to customers selecting the new demand responsive tariffs. Hence, the average bill impact would be lower after demand response savings are accounted for.

For the purposes of this analysis, average residential gas use is assumed to be 45 therms per month, and average electric use is assumed to be 550 kWh per month. Due to the restrictions imposed by AB1X, the average customer would experience only a very small electric bill impact, because the average customer uses very nearly the 130% of baseline quantity. Relatively high gas use is assumed to be 66 therms per month and relatively high electric use is assumed to be 1,000 kWh per month (with a 400 kWh per month baseline allowance). These figures correspond to approximately the 90th percentile of residential gas and electricity usage.

PG&E believes allocation of part of the AMI revenue requirement to core gas customers is appropriate since core gas customers benefit from the automation of their meter reading through reduced meter reading costs, more efficient meter reading, and may benefit from more efficient operations generally.

As shown in Appendix B, the net costs are expected to decline over time, as meter deployment is completed and full operational savings are achieved. Net costs are total costs net of operational savings and do not include demand response related effects, such as avoided procurement costs resulting from dynamic electric rates.

2. Cost recovery

PG&E expects to recover the full cost of the AMI Project brought forth by PG&E and approved by the Commission. In the full AMI Project Application, PG&E will allocate the costs among gas and electric customers and will seek rates to recover the full capital cost investment and on-going operating costs of the Project, less the pre-deployment costs already authorized for recovery in rates. PG&E anticipates establishing appropriate balancing accounts to ensure full recovery of the AMI Project costs, based on methods consistent with PG&E's currently authorized gas and electric base revenue requirements.

II. CASES AND SCENARIOS ANALYZED IN THIS UPDATE

In the October 15, 2004 filing, PG&E analyzed 19 AMI deployment scenarios as directed by the Commission in its July 21, 2004 ACR. In the November 24, 2004 ACR, the Commission directed the utilities to file on March 15, 2005 their "preferred" AMI strategy, and at least one full and one partial deployment case. At this time, PG&E's preferred AMI strategy is full deployment, as described below. PG&E also briefly describes its "base" case and its "partial" deployment cases, and addresses the issue of demand response enabling technology and inclusion of customers over 200 kW.

A. Base Case or "Business As Usual"

For both the October 15 filing and this update, PG&E has constructed a "base case" to capture 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. All costs for the AMI deployment cases are incremental to the base case.

B. Full Deployment Case (Preferred Strategy)

It is PG&E's belief after multiple levels of discussion with equipment vendors that technology exists to automate meter reading for its entire customer base, and provide hourly reads on every electric meter account. The end goal of the Full Deployment business case is to have every PG&E meter served on the AMI platform regardless of demand size.[2]

Full deployment is preferred by PG&E since it will yield the maximum value of operational savings and the maximum value of electric demand response benefits possible. The operational "gap" between costs and savings is greater for the partial deployment case than for

[2] Non-core gas meters are not included in the AMI Project because they were authorized and implemented under a separate proceeding.

the full deployment case. In addition, the partial case has far fewer electric customers with advanced meters able provide demand response benefits to close that gap. Full deployment will spread the fixed costs of AMI (incurred for both a partial and full deployment) over the most meters.

More important, however, it is critical that PG&E's entire utility business, and all of its customers, not merely some subset, share in the benefits of AMI technology. AMI is a tool that will transform both regulatory policy and utility business operations. For this reason it should be deployed throughout PG&E's service territory.

All relevant operational and demand response benefits presented in the Full Deployment Case of this filing are based on 100% implementation. The implementation plan is to begin setting meters in early 2006 and ultimately replace all 5.1 million electric and 4.2 million core gas meter accounts over PG&E's 70,000 square miles of service territory by the end of 2010. This start date is possible if PG&E begins pre-deployment activities in July 2005 to develop the procedures and processes to handle 11,000 or more meter change-outs per day. It will take approximately one year from first meter set for the installation process to be perfected to the point where PG&E can reach the 11,000 per day peak installation rate. The peak rate would be sustained for the next three years and then a ramp down would occur during the remaining 12 months. During the ramp down period, difficult and out-of-the-way installations will be managed. While a relatively small number of meters will likely be in place by summer 2006, it is PG&E's goal to have 1 million meters set by the summer of 2007, at least 600,000 of which would be electric meters.

Detailed assumptions underlying the full deployment case are in Appendix B.

C. Partial Deployment Case

PG&E has also designed a partial deployment case consistent with the direction in the

November 24 ACR. Under that case, PG&E 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 Statewide Pricing Pilot (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 Partial Deployment case economics have been scaled to reflect the smaller build. The partial build is designed to reach 1.9 million electric meters and 1.8 million gas meters over about 48,000 square miles of service territory. The deployment parameters include the same 12 month ramp up to peak installations of 11,000 per day as for a full deployment, but the partial deployment would be completed in approximately 36 months.

The Partial Deployment case analysis is summarized in Appendix C. However, the remaining discussion in this update filing is focused on the Full Deployment case.

D. Inclusion of Customers Over 200 kW

Last fall, PG&E had not studied the potential benefits for the class of electric customers over 200 kW. Since that time, PG&E refined its assumptions and found benefits associated with including these meters in the AMI system and reducing the internal metering support and communication infrastructure for these customers. The business cases reflect savings in the area of data communication and customized billing services, and additional costs for AMI-compatible meters and modules. However, new demand response benefits are not included for this class of customers where interval meters and demand response programs already exist.

E. Technology Cases

PG&E has not included reliability or demand response enabling technology, such as load control switches or smart thermostats, at customer locations as part of its business case in this update analysis. PG&E and its consultants, Charles River Associates (CRA), prepared an analysis of the incremental value of using technology in conjunction with the AMI platform. The analysis was based on the observed response (elasticity) of customers in the SPP. In the SPP, eligible customers with central air conditioning on a CPP tariff without smart thermostats were compared to customers with central air conditioning *and* smart thermostats on the same tariff. Customers who had smart thermostats showed incremental potential peak demand responses in the range of 0.06 kWh/hr to 0.14 kWh/hr above the responses of those without smart thermostats. This incremental demand response benefit translates to an annualized benefit per customer ranging from $6 to $15, depending on the climate zone. The estimated annual revenue requirement to purchase, install and administer a smart thermostat device, with no incentive payments to the end user, is estimated to be approximately $72 per customer. Since the incremental potential demand response benefit is substantially below the estimated annual revenue requirement, PG&E concludes that it is not cost effective to combine a load control/smart thermostat technology with the AMI business case at this time. It is PG&E's intent, however, to ensure that the AMI infrastructure is capable of facilitating a load control/smart thermostat technology if and when a program of that nature is deemed appropriate.

III. OPERATIONAL AND CUSTOMER BENEFITS

This section covers direct utility operational savings and customer benefits. Demand response benefits resulting from customer response to dynamic rates are addressed in Section IV below.

PG&E’s analysis of utility and customer benefits has advanced considerably since October 15, partly due to a better understanding (as a result of both the RFP and reviewing the experiences of other utilities) of the advantages an AMI system can provide. The detailed analysis of utility and customer benefits is discussed in the sections below. The discussion is broken into two broad categories – quantifiable benefits and un-quantifiable benefits. The following table summarizes the most important quantifiable operational benefits identified by PG&E, accounting for 98 percent of the total estimated operational benefits of $133 million annually (for full AMI deployment). There are also approximately $32 million of projected "one-time" operational benefits, the most significant of which are customer-to-transformer assignment, avoided replacement of PG&E's current handheld meter reading system, and deferred meter testing:

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TABLE 2: MOST SIGNIFICANT OPERATIONAL BENEFITS FROM A FULL DEPLOYMENT AMI PROJECT

Benefit category[3]	Present Value Revenue Requirement (PVRR) ($ million)	Annualized Benefit After Implementation (2004 $ million)	Comments
1. Meter reading	$714	$79.2	Includes saved labor and related costs and support functions.
2. Other employee related expenses	$103	$13.4	Additional employee benefit- related savings from labor force reductions.
3. Storm restoration	$74	$7.2	AMI outage data can be used to dispatch crews more effectively and to improve power-restoration processes after significant outages.
4. Avoided time-of-use (TOU) meter maintenance	$62	$6.0	Includes avoided cost of maintaining current fleet of TOU meters, including battery replacements and periodic field calibration.
5. Interval meter program	$62	$6.0	Saved costs from migrating to the mass billing system about 7,000 interval accounts currently handled by PG&E's Advanced Billing System. These include the saved data-retrieval costs of reading these meters today.
6. Reduced call volumes/handle times/customer complaints.	$50	$4.9	Saved costs due to reduced calls to the call centers and reduced length of calls; includes reduced consumer affairs costs.
7. Cash flow improvement	$35	$4.6	AMI will allow meters on summary billed accounts to be read on the same day resulting in improved cash flow.
8. Records exception processing	$45	$4.4	PG&E believes that AMI will reduce the need to address various "exceptions" related to

[3] In this table, PG&E has not used the benefit categories identified by the WG 3 workshops and attached to the July 21, 2004 ACR. Appendices B and C, however, have the benefits broken down and identified by the WG 3 categories.

			meter reading and billing.
9. Avoided Dispatch If Power is On	$44	$4.3	AMI will allow PG&E to perform electronic 'call-aheads' to eliminate the need for dispatching field personnel to locations where power is on.
10. Miscellaneous annual savings	$27	$3.0	
Total Annual Benefit		**$133/year**	
One Time Benefits	**$32**	**Not applicable**	Relates to benefits such as avoided repurchase of handheld meter reading devices that have a one-time or limited-time value
Post Period Benefit	**$290**	**Not applicable**	Net benefit of the business case beyond 2021[4]
Total Benefits	**$1,538**		

A. Quantifiable Utility Operational Benefits

Quantifiable utility operational benefits are savings that are expected to lower utility operational costs, and hence PG&E's revenue requirement. PG&E will continue to revise the savings estimates presented in this filing and refine 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. Meter Reading

More than half of the potential savings predicted from AMI relate to meter reading. AMI will reduce/eliminate the labor and non-labor costs required for regular meter reading and change of party/special reads.[5] Labor costs include management, field employees, and clerical

[4] Post period net benefits are the value of cash flows that belong to the AMI meters placed in service under the business case with life remaining after the stated business case period of 2021. In other words, the meters placed in service in 2006 are expected to produce net benefits through 2025 (i.e., 4 years past 2021). 2007 meter placements will produce benefits through 2026 and so on. After the 20 year life is exhausted, PG&E assumes that a second AMI deployment on the same ramp-in schedule will occur. As a result the net benefit cash flows beyond 2021 are gradually phased out.

[5] [redacted]

employees. Other labor-related cost savings include back-office support staff (customer service, information systems), Itron contract, and reductions in employee injuries and third party claims. Non-labor cost savings include materials, employee-related expenses (e.g., meals, travel allowances and reimbursed mileage, pagers, desktop and cell phones), and company vehicles. The total annual cost savings related to meter reading would be $79.2 million for full deployment of AMI for all electric and core gas accounts.

2. Other Employee Related Expenses

Other employee related costs are expenses that are included as a burden on labor expenses or as an additional benefit to labor savings. The items included in this benefit are pensions, post-retirement medical and life insurance benefits, long-term disability, workers compensation expense, and other miscellaneous costs per employee. The gross savings in other employee related expenses due to headcount reductions in the meter reading work force is $141 million of PVRR offset by $38 million of PVRR for new headcount related to AMI operations and maintenance. Therefore, the net benefit for other employee related expenses is $103 million.

3. Storm Restoration

AMI outage data can be used to dispatch crews more effectively and to improve power-restoration processes after significant outages. Through better information related to customers' individual power status, PG&E's ability to potentially reduce the duration of outages and speed up the restoration efforts will be enhanced. This benefit is estimated to be $7.2 million annually (for full implementation) and is based on benchmark data used to estimate savings possible within the current emergency response and restoration process.

4. Avoided TOU Meter Maintenance

PG&E's current time of use (TOU) meters must have their batteries maintained and their calendars updated. Under full implementation an annual cost of $6.0 million associated with these activities would be avoided.

5. Savings Associated With Billing Interval Meters

Approximately 7,740 accounts are handled by the Advanced Billing group at PG&E due to the fact that the mass market billing system cannot currently accommodate billing for these interval-metered accounts. With the rollout of AMI, PG&E expects to be able to transition all but about 1,000 of the most complex accounts to the mass market billing system, thereby significantly reducing its billing costs for interval metered customers. In addition, significant cost savings are anticipated for the Energy Data Services group, which handles meter reading for these accounts, as well as the load research sample. The transition of these accounts to the AMI system should allow capture of data communication savings, as well as labor savings associated with data acquisition, data-base management, field operations, and data framing. AMI will also eliminate the need to bill TOU customers for meter costs, work currently performed by PG&E's non-energy billing group. The total annual savings from all these activities are estimated at $6.0 million.

6. Reduced Call Volumes/Handle Times/Customer Complaints

PG&E expects that AMI will reduce certain types of calls to the call centers and will also reduce the length of calls.[6] AMI is also expected to reduce the number of customer complaints handled by PG&E's Consumer Affairs department. These savings total $4.9 million per year under full deployment, the components of which are detailed below.

a. Reduced Call Volumes

PG&E estimates that there will be a reduction in four types of calls with the

[6] The call center savings are still uncertain because the details of what usage data will be available and when depends on final technology and vendor selection. For example, whether hourly or monthly gas usage data will be available, and how frequently the data will be read, will affect these estimates.

implementation of AMI:

High Bill/Energy Cost Inquiry (ECI) calls: These will be reduced due to the anticipated decline in the number of meter misreads. Savings are estimated to be $1.1 million per year for full deployment.

Delayed Bill Calls: These will be reduced due to the anticipated decline in the number of unavailable meter reads for billing purposes. Cost savings are estimated to be $0.2 million per year for full deployment.

Estimated Bill Calls: Estimated bill calls should be significantly reduced with an AMI system. The cost savings is estimated to be $2.6 million per year for full deployment.[7]

Meter Reading Concern Calls: These calls are generated by customers calling for a variety of reasons regarding their meter reads. With more timely and accurate meter reading, and the elimination of monthly meter read visits to customers' premises, these calls will decline in number. The cost savings are estimated to be $0.3 million per year for full deployment.

b. Reduced Call Length

If an ECI cannot be resolved on the first call, the issue is referred to an ECI specialist. The specialist then calls the customer back to resolve the issue. PG&E assumes that with AMI the actual time associated with these calls will be reduced because customers will already have access to basic information about their usage that they do not have now without AMI. The cost savings associated with reduced call times is estimated at $0.5 million year for full deployment.

c. Reduced Number Of Customer Complaints

AMI is expected to reduce the number of complaints that are referred to the Consumer Affairs department. The cost savings are estimated to be $0.1 million per year in a full

[7] The affect of AMI on estimated bills is still undergoing further analysis and these savings estimates will be refined in PG&E's AMI Project application.

deployment.

7. Cash Flow Improvement

PG&E provides a summary billing service to customers with multiple accounts. Since many of these accounts are manually read on their regular meter read schedule and then wait for the "master" account to bill, an account that is read one day after a summary bill is issued will wait for approximately 30 days, until the next billing date, to bill (15 days on average). AMI will allow all meters for a summary-billed account to be read on the same day. This process change will generate a cash flow benefit valued at $4.6 million per year starting in the year that full implementation is achieved. This benefit only applies in a full deployment of AMI since many of the summary billed accounts are spread over the service territory.

8. Record Exceptions Processing

PG&E believes that AMI will significantly reduce the need to address various "exceptions" in the billing and metering process which currently require time and effort to be resolved. These include reductions in missing meter reads, meter reads in error, and demand and TOU validations**.** As a result of reduced rebilling of customers, postage and paper expense would also be avoided. The annual savings are estimated at $4.4 million per year for full implementation.

9. Avoided Dispatch To Locations Where Power Is On

Dispatch of employees to physical locations in response to "no-power" calls from customers will be more efficient. AMI will allow PG&E to perform electronic "call-aheads" to eliminate the need for dispatching field personnel to these locations. Electric troublemen are currently dispatched on approximately 48,000 tags annually to customer's residences that result in no findings. These result in approximately 38,000 hours of dispatch and field investigation costs annually that could be avoided with an AMI system. Total savings are estimated at $4.3

million per year for a full deployment.

10. Miscellaneous Quantifiable Utility Savings

Other miscellaneous quantifiable operational savings include the following:

Momentary Outage Detection: PG&E is required to track and report all momentary customer outages. Approximately 6,000 Enhanced Outage Notification (EON) devices are in place within customer homes to notify PG&E via phone of the presence of an outage. Full deployment of AMI technology will allow elimination of the EON program at an annual savings of $0.6 million.

Improved TOU Rate Changes: AMI will provide more efficient programming of customer rates and enable PG&E to implement customers' requested rate changes quickly and without the field visits presently being performed. For example, today a customer changing from a standard rate to a TOU rate, or 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. A quicker implementation of TOU, demand response and other tariff related programs could be achieved with significantly less cost because interval metering would be installed for all customers. PG&E estimates the benefit would be $1.0 million annually for full deployment.

Reduced Inventories: Meter inventories are broken into three different categories: central warehouse, local meter shops, and installer trucks. When electric meters are purchased, they are shipped and stored at a central warehouse for quality assurance. They are then distributed to local meter shops where installers collect them and keep them on their trucks for daily meter work. These inventories are kept based on meter usage and meter types. If one AMI technology were to be fully deployed, the number of meter types would decline and there would be a reduction in electric meter inventories. Based on a 10% inventory reduction after full AMI deployment of a single meter type, the benefit is estimated at $0.1 million annually.

Transmission and Distribution (T&D) Planning: AMI will provide better information for use in T&D system planning. The benefit does not scale with the rate of AMI deployment and would begin when the full system is in place. This benefit, estimated at $0.7 million annually for full AMI implementation, is based on the experience of other utilities implementing AMI solutions.

Load Research Savings: PG&E would avoid $0.6 million per year in costs currently associated with its load research activities.

11. One-time Quantifiable Utility Benefits

AMI will also produce certain one-time benefits that are not recurring. These benefits total about $32 million (PVRR). The most significant one time benefits are as follows:

a. Avoided Handheld Equipment Replacement

AMI avoids the requirement to repurchase handheld meter reading equipment currently used by PG&E. The next scheduled purchase, in 2011, will be avoided at an estimated savings of $8.5 million under full deployment.

b. Deferred Meter Testing

PG&E presently has an annual electric meter test program to monitor accuracy of the entire electric meter population. PG&E incurred $1.6 million for this meter test program in 2004. As AMI is deployed, the existing meters would be replaced with new AMI meters that are all tested for accuracy by the manufacturers. Therefore, PG&E would defer the electric meter testing program during the AMI deployment period. The benefit should start immediately at the beginning of AMI deployment in 2006 and grow to $1.6 million per year in 2010 and decline thereafter. The one-time total benefit would be $9.6 million for full deployment.

c. Customer-to-transformer assignment

As AMI electric meters are deployed, customer assignments to the appropriate transformer will be verified. Based on the actual process currently required to validate customer and equipment assignment, a net one-time cost avoidance of approximately $12 million is expected for full deployment.

d. Scrapped Meter Salvage

With AMI deployment, almost all existing electric meters would be replaced or retrofitted with AMI meters. Many existing meters could not be retrofitted and would be retired. [redacted]

B. Un-Quantifiable Benefits

In addition to quantifiable benefits, there are numerous other benefits from AMI that cannot be quantified, but which nevertheless have value to customers, the utility, or to society:

1. Improved Customer Satisfaction

PG&E believes that AMI will result in a significant increase in customer satisfaction, especially in certain areas of the business, such as billing, where the Commission and customers have expressed concern. AMI is expected to result in a significant improvement in both the accuracy and timeliness of bills:

Timely Meter Reading: The implementation of AMI should result in a significant improvement in overall meter reading timeliness. PG&E expects the number of meters not currently read on time will decline dramatically resulting in most customers receiving bills on a monthly basis.

More Accurate Change Party Bills: Currently when residential customer accounts change in mid-bill cycle, PG&E performs a “soft lock” and prorates usage between the previous and the new occupant. With AMI, PG&E will be able to read the meter for an accurate closing bill for electric meters and for gas meters if daily reads are available.

Reduction in Number of Missed Meter Reads: Currently a certain percentage of meters is inaccessible for reading in any given month. Misses are due to access issues involving plastic cards not being set, dogs, locked gates, blocked meters, etc. AMI technology will be able to read the meters in such situations eliminating a major cause of missed meter reads. Of course, AMI will not address all the causes of missing meter read data (e.g., data errors, system errors), but should provide a significant reduction in missed meter reads. This reduction in missed meter reads, in turn, is expected to reduce the need to issue estimated bills.

Accuracy of Reads: With the implementation of AMI, the number of misread meters (i.e., read entered incorrectly) is expected to decline significantly. While system and data errors may still occur, a major source of meter reading error will be eliminated.

Improved Access to Usage Information: With AMI, customers will have access to more frequent information to monitor their usage. AMI can also provide "on demand" reads.

Access to Customer Premises Not Required: AMI would allow gas and electric meters to be read remotely, greatly reducing the need for employees to access customer premises. Customers would no longer receive requests or reminders to put dogs away, unlock gates, provide keys to accounts, set plastic cards each month, etc. to allow the meter to be read. In addition, third party claims due to meter readers entering customer property would be reduced and/or eliminated.

2. More Accurate Assignment Of Usage To Customers

This category of benefits involves reduction of cross-subsidies currently occurring between customers and customer groups resulting from inaccuracies in metering, or from fraud and theft.

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.[8] 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.

Reduced Energy Theft: With tampering detection capability in AMI systems and electric meters, PG&E expects to improve detection of energy theft and to ultimately reduce it. Implementing AMI is likely to improve PG&E's ability to identify lost revenue in two ways. First, by visiting 100% of PG&E's meter locations during the initial AMI meter installation period, it is anticipated that some percentage of the accounts currently affected by theft will be detected. Second, once the AMI system is in place, PG&E anticipates that additional information could be available to indicate the health of the meter as well as providing "tamper alarms." Such capability will aid in more rapid identification and correction of potential tampering conditions.

PG&E estimates that improved energy theft recovery could be $7.2 million per year. Customers might experience a slight rate reduction due to reduced theft from the system as the costs of the formerly diverted energy are paid for by the responsible party. This benefit, however, would represent a shift in cost responsibility among customers, rather than a reduction in total revenue requirement recovered from all customers. A further benefit from reduced energy theft may accrue to society in the form of saved enforcement resources.

3. Possible New Revenue Sources /New Products and 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

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

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.

4. Increased Load Forecasting Accuracy

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 readings 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 disaggregated estimates of load inputs to the forecasting model by climate zone or area load. A quantification of the benefit is difficult at this time.

Another basic benefit of AMI meters is that PG&E would have better knowledge of individual customer usage. Interval meters would allow better tracking of those customers that opt in and out of various programs such as community choice aggregation (CCA) and direct access (DA). The data gained from interval meters would aid in the load forecasting process and the purchase of capacity and energy. Interval meters would provide the ability to track customer loads in various sub-areas within the service territory, allowing forecasting by sub-areas, and better data regarding customer loads within constrained areas.

5. Gas Operations Benefits

In PG&E's preferred full AMI deployment scenario, all core gas meters would also be read by the AMI system. [redacted] Automated meter reading of gas meters would result in benefits to gas customers as meter reading efficiency is improved. If gas meters were not included, 75 percent of the current meter reading force would need to be retained to read gas meters only.

[redacted]

IV. COSTS

A. AMI System Overview

In its January 12, 2005 business case supplement, PG&E described the overall structure of an AMI system and the different kinds of AMI technologies. An AMI deployment includes four main functional elements. Each functional element is a system or a set of services connected to a system. These elements are described briefly below. PG&E divided its September 27, 2004 RFP along these functions and sought separate bids on each functional area.[9]

AMI System: This system includes the provision of "installation ready" new and/or refurbished meters and AMI modules, the AMI communication network modules, and the AMI System Controller. The heart of the AMI System is the AMI System Controller that provides three critical functions: the management of all communications between users and end devices such as meters; the management of the communication system itself to ensure its reliable operation; and the processing and storage of raw data.

[9] PG&E also sought a load control solution as an additional element of its RFP.

AMI Interface System: The AMI Interface System takes the raw data from the AMI System Controller and prepares it for use by other utility systems such as billing and outage management. The AMI Interface System is the software that will perform the data "framing" function to translate the interval meter readings into billing determinants. No other utility has implemented dynamic pricing for billing purposes on the scale and volume contemplated by the Commission (i.e., default dynamic rates for all customers). As a result significant advance development work and testing will be necessary to validate scalability and operational capability of these systems.

Installation Services: All of the equipment, software, labor, management and other services and resources required to (i) install new and refurbished electric meters, (ii) retrofit gas meter modules and install new gas meters, and (iii) install local network equipment (repeaters, concentrators, etc.).

Project Management and Systems Integration: The provision of overall project management and systems integration services and support to achieve the successful deployment of PG&E's selected AMI solution, including managing the implementation of all of the products and services covered by the other functional areas. This may include the provision of IT integration and project management support to integrate AMI functionality with PG&E's existing billing, outage management, SAP and related systems.

PG&E has still not made any decisions about what AMI technology or combination of technologies it will use. Numerous factors will play into the decision. At a minimum, PG&E's AMI technology will be capable of the Commission's functionality requirements referenced in the July 21, 2004 ACR. In addition, numerous other factors will determine the ultimate choice. As was stated in the RFP, "PG&E will evaluate the merits of each Supplier's proposal with regard to price, functionality, performance, vendor maturity, business terms, product maturity, schedule and overall risk."

B. Technology choice for purposes of this update analysis

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

C. Summary of Major Cost Categories Of An AMI System

There are a number of cost contributors to implementing an AMI system. These are discussed in detail in subsequent sections. However, the following table summarizes the most significant cost drivers of an AMI System:

TABLE 3: COST CATEGORIES FOR FULL DEPLOYMENT CASE

Cost Category	[redacted]	[redacted]	Comments
1. Meters and meter modules (Electric/gas)	[redacted]	[redacted]	Cost of meter materials, materials management and installation. Modules are placed on existing meters where possible, otherwise modules are fitted on new electromechanical meters.
2. AMI Network and Master System Controller	[redacted]	[redacted]	Network interface units at substations; mobile devices; network system controllers.
3. AMI Interface System / Data Processing	[redacted]	[redacted]	Data billing determinant creation, data storage, data processing for other internal systems: billing; outage management; records. Includes billing system enhancement for interval billing.
4. Project integration and program management	[redacted]	[redacted]	Vendor management, end-to-end implementation management.
5. Other deployment costs	[redacted]	[redacted]	Other deployment costs include establishing a network monitoring center, customer inquiries, and development of a customer web portal.
Total	[redacted]	[redacted]	
6. O&M; recurring and non-recurring	[redacted]	[redacted]	Annual operational costs to support and maintain the AMI system. Includes data processing, public network connections, and incremental technical support. Non-recurring costs includes marketing of dynamic rates, and a gas battery replacement program in year 11.
Total System Cost	[redacted]		

D. Detailed Description Of Major Cost Categories

1. Meter and Module Costs

a. Meter Exchange Strategy

PG&E requested that each bid submitted for the AMI meters and networking

[10] All deployment costs shown include a contingency of 12.5%.

infrastructure include an analysis of meters which could be retrofitted with modules on the existing meter or would need to be replaced with a meter that could be fitted with a communications module. To facilitate this analysis, a detailed inventory of PG&E's current meter population was made available to the RFP recipients. [redacted]

b. Number Of Customer Accounts/Meter Conversions

The following table shows the number of accounts or meters that are presently in service. Most of the interval meters are remotely read every day, while some are manually read by technicians because telecommunication is not available at the meter sites. All non-interval meters are read by meter readers monthly.

TABLE 4: ESTIMATED METER CONVERSIONS

	Total meters	Interval meters	Non-interval meters
Electric Meters – Dec. 2004			
Residential	4,375,022	1,919	4,373,103
C&I < 200 kW	502,008	3,007	499,001
C&I > 200 kW	8,725	7,025	1,700
Ag	85,113	930	84,183
Gas Meters – Mar. 2004			
Residential	4,038,703	0	4,038,713
Non-residential	97,162	1,289	95,873

c. Meter Population Growth Rates

Customer meter population growth rates assumed are as follows:

<u>TABLE 5: LOAD GROWTH RATES</u>

Electric		2004	2005	2006	2007	2008	2009…	2015…	2021
	Residential	1.5%	1.7%	1.6%	1.6%	1.7%	1.6%	1.3%	1.1%
	C&I <200KW	1.3%	1.4%	1.4%	1.4%	1.4%	1.4%	1.2%	1.0%
	C&I >200KW	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
Gas	Residential	1.3%	1.4%	1.6%	1.7%	1.7%	1.8%	1.8%	1.8%
	Non-residential	0.4%	0.8%	0.9%	0.8%	0.7%	0.7%	0.7%	0.7%

d. Meter Deployment

Initial meter installation (after test meters) is based on beginning the current meter conversion effort in first quarter 2006. At this point, warehouses must be populated with enough meters and modules to begin a full-scale deployment that is expected to reach the rate of 11,000 electric and gas meter conversions per day. This is the conversion rate deemed necessary to accommodate a ramp-up period to test conversion exception processing, and a "mop-up" period to manage difficult and out-of-the way meter installations, and still install all meters by the end of the fifth year. The conversion labor resources are expected to come from a vendor contract awarded as a result of the RFP. The vendor awarded this contract will handle the following elements of the meter conversion:

- Contracted labor resources that may number 200 – 300 at the time of the peak installation period
- Cross dock inventory storage and staging centers
- Call centers to schedule meter change-out appointments with customers whose meters are inaccessible
- Information exchange to keep customer account records current such as final read on old meters, new meter serial numbers, meter type, etc.

It is expected that about 3% of meter conversions will not be completed by the meter conversion contractor. In these cases, PG&E call centers will schedule the appointment and

PG&E field technicians will complete the meter conversion. Costs for the PG&E conversions are included in addition to the meter conversion contractor costs.

During the five-year meter conversion plan, current metering work will continue for PG&E customers not in the immediate conversion area. For meter failures that require a meter exchange or meter installations for new customer accounts, PG&E technicians will perform this work, as they do today. After January, 2006, all new meter installations will be AMI compatible meters and related communication modules.

e. Electric Meter Costs

Metering costs include the cost of a communications module for those meters that the vendors indicated could be retrofitted. For the meters that cannot be retrofitted, a new electromechanical meter is included with the cost of the communications module. Prices used include all shipping, sales tax, and loadings for warehousing, insurance, etc.

PG&E expects to have to repair sockets in approximately 0.5% of electric meter installations. Materials and labor costs have been adjusted to include these socket repairs. A recent survey of metering assets indicates that about 140,000 of the current meter inventory will require an A-base adaptor. The materials and labor costs have been adjusted to also include the expected installation of these A-base adaptors

f. Gas Meter Costs

As with the electric meters, gas metering costs include the cost of a communications module for those meters that the vendors indicated could be retrofitted. For the meters that cannot be retrofitted, a new gas meter is included with the cost of the communications module. Four percent of current gas meters are known to require replacement, and the materials and labor costs of replacing these meters are included in the business case. Costs used include all shipping, sales tax, and loadings for warehousing, insurance, etc.

g. Failed Electric Meter Replacement

PG&E has not yet determined which AMI meter technology would be deployed in the future and does not currently utilize in its operations any of these new AMI meter technologies. PG&E does not therefore have documented AMI meter failure rates and must rely on the vendors' information on their AMI product failure rates to make its assumptions. [redacted] However, additional AMI modules attached to electric meters would cause a slight increase in electric meter failure rate. Combining the changes in these failure rates, PG&E assumes that total electric AMI meter failures should remain the same as those electric meters that are presently in service at PG&E.

As noted above, PG&E reiterates that it relied on AMI vendor information on electric meter/module, and gas module/battery failure rates. PG&E does not have experience with these AMI technologies to validate these assumed failure rates. The actual failure rates could be higher.

h. Failed Gas Module/Battery Replacement

All core gas meters would be equipped with gas AMI modules, and most meters would remain in service, and not be replaced. Gas AMI modules are considered as independent and additional devices to gas meters, and may fail without affecting the operations of gas meters. Additionally, failed gas AMI modules would be replaced without removing gas meters. Based on vendors' information, [redacted]

i. AMI System Power Usage

The AMI infrastructure (electric meter modules, repeaters, concentrators) will use system power in order to operate (gas modules will be battery powered). PG&E will include the estimated incremental power usage of the AMI system it ultimately selects as a project-related cost in its project justification analysis when it files its full AMI Project application.

2. Network And Master System Controller

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

3. AMI Interface System/Data Processing

As indicated earlier, the AMI Interface System collects, stores, processes, and passes on meter data and alarms from various meter collectors, i.e., AMI system controllers, to various PG&E "legacy" systems and to third parties. The estimated costs are as follows:

TABLE 6: AMI INTERFACE SYSTEM/DATA PROCESSING COSTS

	[redacted]
AMI Interface System	[redacted]
Upgrade the existing billing system to process dynamic TOU rates for all customers	[redacted]
Integration to other core systems such as Enterprise Application Integration (EAI), asset management (SAP), Outage Information System (OIS), Field Automation System (FAS), and the Call Centers.	[redacted]
Contingency	[redacted]
TOTAL	[redacted]

4. Systems Integration and Program Management

Systems integration and program management (SI/PM) costs fall into three broad areas. First is the expense required during pre-deployment to (1) prepare the internal operational processes to be ready for the implementation of automated reading, outage management, call center queries, and other customer service functions; (2) develop internal training, process re-engineering, and procedures for use by operational groups before meters are set and customer interactions change under the AMI system; and (3) prepare for the meter change out process and related data exceptions. Second, the SI/PM effort requires staffing for the term of the deployment to handle all vendor-related issues, scheduling, coordination among labor resources, contracted or not, testing, concentrator turn-up, budgeting, and progress reporting. Finally, SI/PM will require a system integrator to ensure the rapid development of the IT-based interfaces and protocols to ensure that multiple meter automated systems are integrated into the network operations center, the AMI storage and processing server, and ultimately for assurance that data can be collected to bill dynamic rates on a mass basis. [redacted]

5. Other Deployment Related Costs

Other deployment related costs include establishing a network operating center, development of a customer web portal, and the expense of handling customer inquiries to the call center regarding the new metering installation.

6. O&M Costs

a. Marketing/Communications

The estimated costs for marketing/communications will encompass comprehensive customer and employee education and information programs over six years, with some minor ongoing costs for 2011 and beyond. The marketing/communications activities include:

1. Customer research
2. Advertising (print, radio, TV, direct mail, CPP educational materials)
3. Collateral (brochures, information kits, door hangers)
4. Employee education
5. Costs For Opt-In Promotion

Estimates include the design and production of materials, postage, and the costs associated with paid media. The costs are expected to total approximately $35 million for a full deployment over the five-year rollout, and then continue at $0.2 million per year thereafter.

b. Network Operations Center

PG&E will operate a staffed 24-hour-per-day network operations center (NOC) due to the importance of receiving all meter reads on an hourly basis. The NOC will be available to monitor and support the technology in the field. The network operations center will also be responsible for maintaining all connections to the system controller in working order, including managing digital wireless services purchased from cellular phone companies or other public network service providers. Any operational reporting of network operations will be generated by the staff at the NOC. The NOC will also provide operational support during outages. It is PG&E's intention to use the full AMI system capability to monitor, control, and reduce restoration times as much as possible during outage periods. The NOC will operate the system during outage periods to perform monitoring, tracking and reporting on outage information. [redacted]

c. Information Systems

Each of the new information systems will require annual labor and licensing expense for maintenance and operations. The table below shows the estimated expense of the annual operations for the full deployment implementation of new information systems. In addition to these costs, the business case has a server replacement expense every three years for anticipated server renewal.

<u>TABLE 7: INFORMATION SYSTEMS O&M</u>

	[redacted]
Master Controller	[redacted]
AMI Interface System	[redacted]
O&M for upgraded billing system	[redacted]
O&M for legacy systems	[redacted]
Total Information Systems annual O&M	[redacted]

d. Gas Service O&M Costs

(1) Gas Meter Reading

To maximize the business case benefits, PG&E assumes that all meters are automated with an efficient network for the customer served. If gas meters were not automated simultaneously with electric meters, approximately 75% of the meter reading benefit cannot be realized. [redacted]

(2) Gas Meter Corrosion Testing

Currently gas meters are checked for corrosion by meter readers. In the full deployment scenario, all gas meters will have to be inspected every three years at a cost of $2.9 million per year.

e. Other O&M Costs

Other operations and maintenance costs are expected to cost $3.3 million per year on a recurring basis. The most significant of these are:

[redacted]

Public Wide Area Network: Recurring annual fees paid to cellular or landline telecommunication service providers is estimated at $0.7 million per year in a full deployment scenario.

Customer Web Portal Access: Recurring annual expense of maintaining the customer web portal access is estimated at $1.0 million per year in a full deployment scenario.

V. DEMAND RESPONSE BENEFITS

A. Introduction

Due to the significant improvement in the business case, demand response benefits have assumed a less important role in evaluating AMI deployment. While PG&E continues to believe one of the most important benefits obtainable from AMI is demand response, the importance of debating the precise value of key drivers of demand response, such as participation rates, elasticities, and value of capacity has diminished. The operational “gap” between the costs and benefits for a full AMI deployment case (PG&E’s preferred deployment strategy) has shrunk dramatically -- from $1,162 million to $ 409 million. Thus, about 79 percent of the costs of the project are covered by expected savings in utility costs. At this level, AMI is potentially cost effective under certain opt-in electric demand response scenarios.

Analysis based on the SPP results indicates that the average residential customer on a demand response tariff with a CPP price set at $0.90 per kWh can be expected to reduce peak demand by about 23% or 0.29 kWh/hr. Based on the utility operational “gap” of $409 million PVRR, approximately 25% of customers would need to demonstrate this peak demand reduction on each of 15 CPP days on average through 2021 to produce sufficient demand response benefit to cover the gap (based on an $85 per kW-yr capacity value). In summary, for the AMI project to be cost effective, one in four of PG&E's residential customers would need to reduce their peak demand on average by 0.29 kWh/hr on critical peak pricing days. This would be equivalent to turning up the thermostat control on a central air conditioner from 72 degrees to 78 degrees during the five hour CPP event (for an average user – large users would yield a much greater load drop) or shifting operation of a swimming pool pump out of the CPP hours. Moreover, achieving additional demand reductions from small and medium-sized commercial customers would lower the necessary average load reductions or participation levels by residential customers that would be needed to close the gap. It seems reasonable to expect that the Commission will be able to develop demand response programs with AMI that could achieve this level of benefits or better.

In this updated business case filing PG&E estimates the electric demand response possible with an AMI system based on the CPP program structure tested in the 2003-2004 SPP. This demand response includes both the immediate reduction in load that can be obtained through CPP, as well as reshaping the load curve via Time-Of-Use (TOU) rates. The SPP provides a rigorous analysis to document proven, obtainable demand response using a CPP structure. However, this analysis is merely a proxy for what might happen with AMI-enabled demand response over the next 20 years. As CPP and other rate structures are tried and analyzed over the years, the ability to develop programs that create targeted, reliable demand response will certainly improve. For example, the AMI technology would support an array of demand response options from dynamic price signals to direct load control to tariff options that allow the customer to choose the level of service (e.g., maximum demand imposed at the system peak). Moreover, AMI technology will also support the State in implementing its preferred initiatives in a variety of areas, including energy efficiency and distributed generation, and will allow policy makers and utilities to better implement, manage, and evaluate programs in all these areas. Thus, by authorizing investment in this technology, the Commission is enabling a host of potential avenues for obtaining benefits.

Once AMI is implemented, PG&E also expects that a variety of technology “add on” options which capitalize on the AMI infrastructure will become available over time. For this reason, PG&E is designing an AMI system that will be compatible with a wide variety of technology options. PG&E would file separate applications for these technologies in the future.

B. Evaluation of CPP Demand Response Benefits For Customer Below 200kW

Demand response benefits are based on system peak load reductions by customers responding to pricing signals. These benefits include the avoided capacity costs of procuring incremental electric resources to generate 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 and/or shift usage from a more expensive to a less expensive period, there are benefits stemming from reduced energy procurement costs. These benefits were estimated for customers below 200kW as an incremental benefit of an AMI system. The larger customer class is already interval-metered and the potential demand response benefits associated with those customers are included in the base case assumptions.

The method of estimating demand response benefits from new tariffs consists of two steps. The first step is to estimate the price responsive impacts of MW and MWh reductions during different time periods, and the second step is to calculate the value of those reductions. The scenarios analyzed by PG&E are described in section C below. To account for variability in the estimate of demand reduction, high and low values are also estimated as described in section D below. The MW and MWh reductions are then valued using the avoided cost of capacity, energy, and transmission and distribution as described in sections E and G. A detailed description of the method and assumptions used to determine the customer demand response benefits described in this filing are listed in Appendix D.

This analysis of the value of demand response assumes that the estimated MWs of load reduction 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 MW of demand response. If demand response is not counted toward meeting resource adequacy requirements, it will have substantially less value than the

$85/ kW-year specified in the July 21, 2004 ACR and used in this analysis. PG&E considers the avoided cost valuation of demand response to be an open question, to be addressed further in PG&E's AMI Project Application.

C. Demand Response Scenarios Analyzed

For this business case update, PG&E analyzed six full and six partial rollout demand response scenarios. Each scenario represents a combination of features/assumptions as described in the table below. Only one scenario for each deployment strategy, full (scenario 13) and partial (scenario 11), replicates assumptions of a scenario from the October 15, 2004 filing. PG&E provided these scenarios in order to facilitate comparison with the estimates provided in the October 15, 2004 filing. Due to three significant updates in the demand response estimation assumptions, there is a net reduction in the demand response for the same scenarios analyzed on October 15. First, all the price elasticites were updated using the recent results of the 2004 SPP analysis. Second, the installation schedule was revised resulting in a relatively small population of meters installed by summer 2006. Third, the implementation of price responsive rates for a significant population of meters is currently assumed to be summer 2007 (as opposed to summer 2006 assumed on October 15) and only those customer meters installed on or before April 1 of each year are assumed to contribute to demand response in a given year (as opposed to the average installed during the year as assumed on October 15).

TABLE 8: DEMAND RESPONSE SCENARIOS ANALYZED (FULL DEPLOYMENT)[11]

Scenario							
Number	Type (see note at foot of table)	On Peak Price	Participation assumptions	Default Tariff	Other Tariffs	Deployment	Technology (see section II.E above for explanation)
1 (Scenario 13 from October 15)	A	$0.75	One time 20% opt-in	Current	CPP-P	Full	None
2	B	$0.90	Ramp up 10-30% Base	Current	CPP-P	Full	None
3	C	$0.90	Ramp up 10-40% Base	Current	CPP-P	Full	None
4	D	$0.90	One time 80% opt-out	CPP-P	Current	Full	None
5	B	$0.90	Ramp up 10-30% Base	Current	CPP-F	Full	None
6	C	$0.90	Ramp up 10-40% Base	Current	CPP-F	Full	None

Where:
Type indicates Price / Participation groupings
A = $.75 with one time 20% participation with opt-in
B = $.90 with ramp up participation Base 10-30, Low 0-10, High 15-40
C = $.90 with ramp up participation Base 15-40, Low 0-20, High 15-50
D= $.90 with one time 80% participation from opt-out

As shown in the table above, all six scenarios are analogous to scenarios produced for the October 15 filing, with modifications to two more features. A critical peak price of $.90 was used (instead of $.75) in five of the scenarios and the opt-in (voluntary) participation rates were modified in four of the scenarios. Each of these changes is discussed in further detail below.

[11] Partial deployment scenarios are shown in Appendix D.

1. CPP Price

In the demand response estimation calculation, an increased critical peak price of $.90 was evaluated in five of the scenarios. This price represents an increase from a value of $.75 per kWh used in the October 15, 2004 filing. This change was implemented to highlight the impact of price on the benefits estimation outcome and to capture the point of diminishing returns on price given the demand response function. It appears from the analysis that the increase in price added little to overall demand response, producing an increase of only 2 percent. Note that the rates used in this analysis are illustrative of potential demand response tariffs only, and are intended to capture the range of demand response that might be obtained from tariffs that would be offered over the next twenty years. A further discussion of possible rates that could be offered in summer 2006 and rate impacts associated with this specific rates are included in Section VII below.

2. Opt-in Participation Rates

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. It is not practical to assume that all customers who will eventually use demand response tariffs will understand and accept those rates on the first day they are offered. As such PG&E has reflected a "ramp up" of customer participation in four of its five opt-in scenarios.

D. Addressing Uncertainty

To capture uncertainty inherent in the above assumptions, Charles River Associates (CRA) performed a Monte Carlo analysis on the rate of customer price responsiveness. This is measured through two elasticities of demand: the elasticity of substitution and the price elasticity of daily electricity consumption. The former measures the rate at which the customer substitutes off-peak usage for peak usage, in response to a change in the ratio of peak to off-peak prices. The latter measures the rate at which the customer changes daily electricity consumption in response to a change in the daily price of electricity, which changes as the ratio of peak to off-peak electricity prices changes. Appendix D lists the mean values and standard errors of all the elasticities that have been used in estimating demand response by rate type. A second analysis placed an upper and lower bound on the customer participation rate under different rate scenarios. The 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 peak/off-peak substitution and daily 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 D.

E. Value Of Peak Capacity And Energy

In this analysis, PG&E has continued to use the avoided capacity cost figure of $85/kW-yr provided by the July 21, 2004 ACR. PG&E updated the avoided energy costs based on a current estimate of forward energy prices. PG&E still regards the appropriate value of capacity and energy for AMI demand response as an open issue. The valuation of capacity continues to be debated in various forums including in Phase 3 of Rulemaking 04-04-025. In its AMI deployment application PG&E will further address this issue.

As noted in its October 15 filing, PG&E performed no separate or additional valuation of reliability beyond that captured by the $85/kW-yr figure specified by the Commission. However, PG&E notes that according to Decision 04-10-035, issued October 28, 2004, demand response also reduces the amount of planning reserves (currently 15% of peak demand) associated with load; therefore, the total amount of reduced capacity procurement would be 115% of dependable demand response. This additional benefit has been accounted for in the analysis.

PG&E has found that the total value of the demand response is almost directly proportional to the avoided cost of capacity value used. For example, in full deployment demand response scenario 1 (see table above), the mean expected value of demand response using an avoided cost of capacity of $85/kW-year is $186 million. If the avoided cost of capacity were twenty percent lower per kW-year, or $68, the value of the demand response would be $149 million. Conversely, if the avoided cost is valued at twenty percent higher per kW-year, or $102, the value of the demand response would be $223 million.

F. Peak Day Forecast Risk Associated With CPP Day-Ahead Design

In its November 15, 2004 comments on the utilities' October 15 business case filings, the California Coalition of Union Employees (CUE) noted that given the impossibility of perfect forecasting, "any claim of annual peak demand reductions of more than 0.8 - 6 percent [of the utilities' peak], which is based on customer responses to the CPP day prices in a CPP tariff, is probably overstated." (CUE comments, p.17). PG&E acknowledges its inability to perfectly forecast load day-ahead, and to fully capture the top 15 peaks of the year with a 15-event CPP program. For this reason, CRA's model estimates the CPP demand response as the average demand response over a random 15 of the highest 25, rather than the 15 highest demand days. Additionally, parties should recognize that AMI is an enabling technology that gives the Commission the ability to implement many more tariff options than the CPP program assumption presented in this filing. For example, "day-of" programs, real time prices, or technology-backed options could all address this issue.

G. Transmission and Distribution Benefits

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 such temporary "over-capacity" conditions would 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 would "flatten-out" and the temporary "surplus capacity" generated by the reduced demand would be "consumed" by annual load growth to the point where T&D capacity expenditure levels would 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 D.

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

H. Critical Peak Event Notification Costs

Under each demand response scenario, benefits must be offset by customer CPP event notification costs. In the October 15, 2004 filing, no costs were factored in for this activity, since it was assumed that notification would be by media announcements. However, PG&E now believes that it is cost effective to call all participating customers in advance of a CPP event. A third party vendor that specializes in these types of mass communications would be used to handle these automated outbound calls. While this is a cost element and not a benefit, it is included under demand response since it is a cost that varies with participation rate. In addition to the notification call cost, each demand response scenario has an expected expense for rate inquiries and the 'option' selection from customers. These costs vary by demand response tariff scenario, and are subtracted from the expected scenario value as shown in the summary results table (Section VI below). In calculating demand response benefits under each scenario, PG&E subtracted the total notification and rate specific communication costs based on the assumed participation level for that scenario.

VI. SUMMARY OF RESULTS

A. Utility Cost and Societal Perspective Tests

PG&E conducted two separate cost benefit analyses. The first includes all costs from a utility revenue requirement perspective, i.e., it compares the net present value revenue requirement (PVRR) of total AMI costs against utility cost savings (the operational "gap") to the net present value of the demand response related benefits. This comparison captures the business case perspective from the utility's standpoint. Second, PG&E has also performed a "societal" perspective test. This test was required as part of the November 23, 2003 "Assigned Commissioner's Ruling and Scoping Memo," p. 4. While no guidance was provided on how to perform this test, PG&E attempted to capture this perspective by removing cost elements that represent transfer payments between different sectors of the economy, such as taxes, from the total operational costs and benefits; however, no adjustment has been made to the demand response related benefits. The following table summarizes the results of both tests for PG&E's preferred full deployment rollout:

TABLE 9: RESULTS OF UTILITY COST TEST AND SOCIETAL PERSPECTIVE TEST FOR FULL DEPLOYMENT[12]

Full Deployment	**PVRR - Utility Cost Test: $409M** **PVRR – Societal Perspective Test: $168M** **Demand response scenario:**					
	#1	#2	#3	#4	#5	#6
Default rate CPP type Participation	Opt-in: CPP-P 20%	Opt-in: CPP-P 10-30%	Opt-in: CPP-P 15-40%	Opt-Out CPP-P 80%	Opt-in CPP-F 10-30%	Opt-in CPP-F 15-40%
2011 Megawatt Offload (MW)	231	385	513	1,027	400	533
Customer Response – ($PVRR – mean)	$186M	$281M	$371M	$821M	$298M	$394M
Transmission & distribution capital deferment – ($PVRR – mean)	$36M	$54M	$73M	$161M	$56M	$75M
Communications/ Event Notification Costs ($PVRR - mean)	$(15M)	$(18M)	$(21M)	$(35M)	$(18M)	$(21M)
TOTAL VALUE ($PVRR – mean)	**$207M**	**$317M**	**$423M**	**$947M**	**$336M**	**$448M**

Low Scenario Value ($PVRR)	$79M	$76M	$160M	$575M	$80M	$169M
High Scenario Value ($PVRR)	$361M	$484M	$610M	$1,218M	$509M	$642M

Under the utility perspective test ($409 million operational gap), five of the six demand response scenarios cover a range with benefits high enough to show justification for the AMI project. Under the societal perspective test ($168 million operational gap), all demand response scenarios cover a range with benefits high enough to show justification for the AMI system. The low and high scenarios were created with Monte Carlo simulation of price elasticities combined with low and high expectations of participation. The avoided cost of capacity is held constant at $85 kW-yr in all scenarios.

[12] The results of the utility cost test are also summarized graphically in Chart 2, p. 4 of this filing.

B. Calculating Present Value Revenue Requirements (PVRR) Of Costs And Benefits

PG&E's evaluations of AMI are based on a cash flow analysis from 2005 through 2021, with a post-period benefit calculation under the assumption that the metering assets purchased have an effective 20 year life. PG&E took the costs of purchasing the equipment and operating for the project term, net of operational benefits, and discounted back to the base year of 2004 at the Weighted Average Cost of Capital. This figure was then adjusted into a PVRR by accounting for the effects of state and federal taxes.

1. Tax Calculations and Depreciation Methods

A combined Federal and State effective tax rate of 40.75% is assumed. Tax depreciation for the new system is based on the following:

TABLE 10: TAX ASSUMPTIONS

Item	Federal Tax Treatment	State Tax Treatment
Meter modules	15 years	24 years
New meters	20 years	20 years
Network concentrators	15 years	24 years
IT hardware & licenses	5 years	5 years
IT software development	Expensed	Expensed
SI and Project Management	Expensed	Expensed

2. Weighted Average Cost of Capital

PG&E used 7.6% as the after-tax Weighted Average Cost of Capital to calculate cash flow Net Present Values. PG&E's current incremental cost of capital is 7.6%. This rate is based on PG&E's cost of debt, preferred equity, and common equity of 6.1%, 6.42%, and 11.22% respectively. These costs are computed into a weighted average after-tax cost of capital by using the authorized capital structure as shown in the table below:

TABLE 11: WEIGHTED AVERAGE COST OF CAPITAL

Type	Ratio	Cost	Before- tax	Calculation	After-tax	Used
Debt	45.5%	6.10	2.78	X (1-tr)	1.65	
Preferred Stock	2.5%	6.42	0.16		0.16	
Common Stock	52%	11.22	5.83		5.83	
	100%		8.77		7.64	7.6

3. External Financing Of AMI Infrastructure (Outsourcing)

As PG&E explained in its January 12, 2005 supplemental business case filing, in PG&E's view outsourced meter ownership (i.e., leasing) of meters may not be economical; utility ownership and financing is likely to be the least cost solution. The likely validity of this assumption has been demonstrated by the responses to PG&E's September 27, 2004 AMI RFP: PG&E did not receive any bids proposing to lease AMI meters to PG&E. Nevertheless, based on a single bid proposing to lease an AMI communications network to PG&E, PG&E estimates that leasing an AMI meter infrastructure could cost up to 20 percent more than conventional ownership and financing.[13]

The key reasons lease financing is not likely advantageous for AMI are as follows (These reasons are discussed more fully in PG&E's January 12, 2005 supplemental business case filing):

- Given PG&E's "BBB" senior secured rating, lenders are unlikely to offer terms that are better than what PG&E could secure through its own conventional borrowing. A lease will be treated as a "100% debt equivalent" with the ratings

[13] There are examples from the mid-90's of other utilities in the United States that have deployed advanced metering using outsourced AMI contracts. However, PG&E is unaware of any outsourced AMI ownership contracts since 1999. Presumably this reflects both the utilities' and the vendors' lack of interest in outsourcing as a feasible option in today's market.

agencies, displacing lower cost conventional debt.

- AMI hardware does not lend itself to lease financing given the specialized function of the equipment and the strategic role this infrastructure is expected to play in PG&E's daily operations. If a lessor was required to provide financing, the charge would be high to compensate for the high technology risk (depreciation/ obsolescence) and low re-sale value for the equipment.
- The lack of control/ownership of the assets could expose PG&E to significant customer satisfaction issues if there are disputes with the vendor (or other business failures stemming from the vendor managing the AMI equipment) resulting in an interruption of service.
- Outsourcing ownership also exposes the utility to the financial stability of the vendor.

PG&E remains open to the possibility that a vendor could propose leasing terms or a performance-based operating contract that could provide economic benefits to ratepayers. However, based on economic logic, the nature of the assets, and the company's experience, this would appear to be highly unlikely. Moreover, the limited data that vendors provided regarding outsourcing supports this expectation.

C. Revenue Requirements

PG&E has estimated illustrative incremental net revenue requirements needed to support PG&E's AMI business case update. The analysis period is 2006 through 2021, and PG&E has excluded recovery of any capital-related AMI expenditures after 2021 and the ongoing revenue requirement associated with pre-deployment expenditures. The separately computed gas and electric revenue requirements presented here compile all the capital-related costs, operating expenses, and savings into an income statement format to estimate the additional amount of revenue needed from customers to recover AMI deployment costs. This amount of revenue is known as the revenue requirement or cost of service.

Table 12 summarizes the preliminary net AMI-related revenue requirements for PG&E's preferred full deployment case. The partial deployment scenario revenue requirement is shown in Appendix C. These business plan cases reflect the operating and customer benefits described in Section III above and the deployment costs identified in Section IV. The revenue requirement analysis reflects distribution and customer service revenue requirements incremental to those adopted in PG&E's 2003 GRC, with adjustments made through 2006. PG&E's 2003 GRC did not include any costs for savings related to AMI services. Therefore, PG&E's presentation in this proceeding includes the full incremental revenue requirements associated with PG&E's AMI Project proposals (excluding pre-deployment activities).

The demand response-related benefits (avoided procurement, T&D) discussed in section V above are not included in PG&E's net revenue requirements since these benefits are dependent on customer behavior and should not be viewed as a utility cost saving unless they materialize in the future. To the extent these savings occur, they will be reflected in customer rates at that time.

1. Capital Additions and Related Revenue Requirements

The primary capital additions (or major capital cost drivers) for AMI Project deployment include (1) metering system and communications network, and (2) information technology (IT) systems costs. PG&E identified the capital additions separately for gas and electric rate base, and then classified them by plant type, thereby assigning the appropriate book and tax treatment. These classifications include: (1) meters, (2) modules, (3) concentrators, (4) IT equipment, (5) software, (6) vehicles, and (7) programming. PG&E did not include any future capital savings such as the avoided replacement of handheld equipment or load research surveys in the revenue requirement calculation. These capital savings refer to delayed-or non-expenditures, and until these investments need to be replaced, there is no immediate ratepayer savings.

PG&E directly assigned the meters, modules, vehicles, and concentrators to gas or electric rate base. For other common plant additions such as the IT equipment, software and programming, PG&E designated a common allocator to assign these costs. For consistency with the methods used in GRC proceedings, PG&E allocated these common capital costs by totaling the cumulative number of deployed AMI meters for each year and calculating the corresponding percentage of gas and electric meters. These percentages are multiplied by the AMI capital additions to allocate the costs between gas and electric rate base.

As discussed above, PG&E will begin placing meters in service in 2006, and ultimately complete full-deployment in 2011. As the AMI meters are deployed, replaced meters will be retired. No additional adjustment to the depreciation reserve was made for salvage or the cost of removal.

For the incremental capital expenditures, revenue requirements are calculated to recover the investment through depreciation, the return on the investment through the application of the adopted cost of capital (return on rate base), state and federal income taxes (including the timing differences of costs between book and tax calculations), and deferred taxes. While all software is capitalized for tax, only software that exceeds $5 million is capitalized for book accounting. In the deployment cases, PG&E expensed all software that fell below the $5 million threshold for book accounting, but capitalized this same software for tax. As with the capital additions described above, the below $5 million software additions also generate rate base-related expenses such as tax depreciation and deferred taxes.

The elements of rate base included for AMI costs are: utility plant in service, less deferred taxes, less accumulated depreciation. Utility plant in service consists of the accumulated original undepreciated investment in plant and equipment that is used and useful in rendering the services that are required by AMI deployment. In developing the associated rate base, certain deductions are made. A deduction is made for the accumulated deferred taxes associated with these assets. These are taxes that have been paid for by the customer, but PG&E has not yet paid to the Internal Revenue Service (IRS). Plant is reduced by the amount of depreciation reserve, i.e., the accumulated depreciation already taken in prior years. Depreciation expense is calculated using a straight-line, remaining-life method and using Commission-approved rates from PG&E's May 1, 2004 depreciation accrual rate schedules. The return on rate base is calculated using PG&E's 2005 adopted cost of capital from D. 04-12-047.

2. Expenses and Benefits Revenue Requirements

The incremental expense revenue requirement generally consists of O&M expense, Administrative and General (A&G) expense, property tax, business, and other taxes. An allowance for franchise fees and uncollectible accounts expense (FF&U) is added to this revenue requirement. In the deployment cases, the O&M and A&G expenses and savings are based on estimates described in Sections III and IV. Because these estimates excluded provisions for non-burden benefits and insurance and casualty costs, PG&E has adjusted these numbers to reflect the additional A&G costs.

PG&E has categorized the expenses and savings by FERC functional group: (1) Distribution, (2) Customer Accounts, (3) Customer Services, and (4) A&G. Property, business, and other taxes are based on the currently effective tax rates. PG&E applied FF&U factors of 0.009673 (gas) and 0.007541 (electric) to the entire revenue requirement. These FF&U factors were adopted in PG&E's 2003 GRC Settlement Agreement.

After categorizing the expenses and savings, PG&E either directly assigned or allocated them to electric or gas cost of service. As with the capital additions, the allocation for those costs common to both electric and gas is computed by taking the cumulative number of meters for a given year and calculating the percentage of gas and electric meters. These percentages are multiplied by the total expenses and savings for a given year, creating a gas and electric breakdown for each individual category.

To estimate the incremental net AMI-related revenue requirement impacts, the expected cost savings or benefits derived from AMI implementation are deducted from the (gross) revenue requirement. These revenue reductions include: (1) revenue cycle services benefits; (2) reductions in meter reading costs; (3) timing differences between the existing meter tax write-off and scheduled depreciation; and (4) O&M and A&G related savings. In the revenue requirement model, these savings are reflected as negative operating expenses.

3. Summary of Revenue Requirements Results

For the business case, PG&E has estimated illustrative revenue requirements for the period 2006 through 2021. The table below summarizes these annual incremental revenue requirements for full AMI deployment, showing electric and gas separately. The electric revenue requirement peaks in 2009 and then begins to deliver net utility cost savings in 2015. The gas revenue requirement peak also occurs in 2009, and then peaks again in 2018 before it declines in 2021. This additional increase is the result of a gas battery replacement program that PG&E expects to initiate for the gas meters in 2017. Appendix C shows comparable estimates for the partial deployment scenario.

These revenue requirement estimates are illustrative and are presented to demonstrate the magnitude of costs that will need to be recovered in future years as well as the expected future savings in utility costs that result from the AMI project.

TABLE 12
AMI INCREMENTAL REVENUE REQUIRMENTS (FULL DEPLOYMENT)[14]

	2005	2006	2007	2008	2009	2010	2011
Full Deployment - Electric							
Gross Incremental Revenue Requirements		$58,264,362	$67,396,760	$100,259,990	$134,205,316	$154,030,028	$145,838,270
Plus:							
Expected O&M and A&G Reductions		-$7,887,336	-$16,577,041	-$23,632,937	-$38,068,036	-$49,862,607	-$55,314,091
Franchise and Uncollectibles		-$75,857	-$159,430	-$227,291	-$366,121	-$479,555	-$531,985
Expected Capital Reductions		-$729,513	-$7,461,672	-$24,261,685	-$39,032,208	-$52,940,886	-$60,060,372
Franchise and Uncollectibles		-$7,016	-$71,763	-$233,338	-$375,394	-$509,161	-$577,633
Net AMI Incremental RRQ	$24,024,375	$49,564,640	$43,126,853	$51,904,740	$56,363,557	$50,237,818	$29,354,190
Full Deployment – Gas							
Gross Incremental Revenue Requirements		$43,162,520	$43,742,220	$63,019,328	$83,136,901	$96,742,753	$93,830,383
Plus:							
Expected O&M and A&G Reductions		-$197,918	-$1,856,869	-$5,119,404	-$8,305,813	-$11,135,472	-$12,589,622
Franchise and Uncollectibles		-$2,333	-$21,889	-$60,348	-$97,909	-$131,265	-$148,406
Expected Capital Reductions		-$497,030	-$5,335,010	-$18,241,257	-$29,446,580	-$40,233,212	-$45,964,223
Franchise and Uncollectibles		-$5,859	-$62,889	-$215,028	-$347,116	-$474,269	-$541,826
Net AMI Incremental RRQ	$14,954,483	$42,459,380	$36,465,562	$39,383,291	$44,939,483	$44,768,534	$34,586,306

VII. RATES ANALYZED AND BILL IMPACTS

PG&E developed preliminary Results of Operations (RO) estimates for the full and partial AMI deployment scenarios, as presented in Section VI.C above of this update filing. The preliminary RO estimates give a net revenue requirement for each year of the study horizon, reflecting capital and operating costs net of estimated operating benefits. For the purposes of this update filing, PG&E considers rate design and rate impacts separately for: (1) recovery of the net AMI-related annual revenue requirements as developed in the preliminary RO estimates; and (2) class-neutral time-of-use (TOU) and critical peak pricing (CPP) rate designs for the new demand response tariffs for which an AMI system would serve as the enabling technology.

[14] While pre-deployment costs were not forecasted (projected or reflected) in the 2006 through 2021 business case estimates, the table does show approximately $39 million of initial revenue requirement spending that PG&E has requested to recover from both gas and electric customers for pre-deployment activities beginning in 2005.

To the extent that the preliminary RO estimates show a small net positive revenue requirement for each year of the study horizon, this component of the AMI-related rates would have a small positive bill impact for nearly all customers. Over the twenty-year period, avoided procurement costs resulting from demand-response programs would be expected to offset some or all of this bill impact. However, avoided procurement costs will be more significant in the later years after all meters are installed and PG&E and customers have gained experience working with dynamic rates. In the early years, however, there is likely to be a small positive bill impact for nearly all customers, even after demand response benefits are considered.

PG&E's demand-response tariffs would be designed on a revenue-neutral basis by customer class. Some customers within each class would face small increases, while others would realize decreases. However, revenue-neutral rate designs are developed under the assumption of no change in actual usage patterns. When the effects of customer response to new TOU and CPP prices are factored in, many more customers would have the opportunity to realize bill savings, producing net benefits to offset (or exceed) those bill impacts associated with recovery of the net capital and operating costs.

A. Rates and Bill Impacts – Net AMI-Related Capital and Operating Costs

The PVRR of net AMI-related capital and operating costs (operational "gap") is $409 million for the full deployment case. As shown in Table 12 (above), the full deployment case revenue requirement starts at approximately $90 million in 2006, increases to approximately $100 million for 2009, and then declines over the remainder of the study horizon.

PG&E would propose to recover these costs as part of its standard distribution revenue requirement. The RO model estimates divide the net annual revenue requirement between the gas and electric departments based on total numbers of gas and electric meters. The resulting gas and electric revenue requirements are then allocated to each customer class in proportion to each class' share of total distribution revenue.

The peak year for recovery of AMI-related net capital and operating costs would be 2006 for the partial-deployment case and 2009 for full deployment. For 2009, the net monthly combined residential gas and electric bill impact for the full-deployment case would be approximately $0.82 for average-usage customers, and $2.95 for high-usage customers.

PG&E's current gas and electric rate schedules do not include customer charges for residential customers, so all metering and customer-related costs are recovered through volumetric charges for these customers. For PG&E's residential electric customers, the net rate recovery for the first several years of the full-deployment case correspond to approximately $0.50 per customer per month, and this would translate into an average volumetric charge of approximately 0.1 cents per kWh. However, PG&E expects AB1X constraints to continue to apply to residential electric customer rates at least through 2011. This would limit the applicability of any new AMI-related net capital and operating rate adjustments to non-exempt upper-tier usage (above 130 percent of baseline quantities). Rate recovery at the level of $0.50 per month for these costs would then translate into increased charges for Tier 3 and Tier 4 usage of approximately 0.4 cents per kWh. For PG&E's residential gas service customers, net rate recovery for the first several years of the full-deployment case correspond to approximately $0.70 per customer per month (at the peak year of 2009), and this would translate into increased volumetric charges of approximately 1.6 cents per therm.

The average residential customer using 550 kWh per month has very little upper tier usage and so would have a net electric bill impact of only $0.12 (assuming 30 kWh of upper-tier usage). However, a high usage customer with average usage of 1,000 kWh per month (and 480 kWh of upper-tier usage) would have an average bill impact of $1.92.

For PG&E's core gas customers, an average residential customer who uses 45 therms per month of natural gas, would see a bill increase of $0.66 per month during the first year of full-deployment, and a maximum bill increase of $0.70 per month during the 2009 peak year of AMI revenue recovery. The corresponding figures for a high-usage gas customer with average use of 66 therms per month would be $0.97 in 2006 and $1.03 in 2009.

PG&E's projected gas and electric class-average rate changes for 2006 through 2009 are provided in Appendix B for the full-deployment case, and in Appendix C for partial-deployment. As discussed above, the class-average rate tables provided in Appendices B and C show those projected rate changes attributable to recovery of the projected net AMI-related annual revenue requirements, as developed in the preliminary RO estimates.

B. Rates Analyzed for Demand-Response Tariffs

PG&E developed the demand-response estimates summarized in Section V of this update filing based on summer 2003 and summer 2004 analysis results from the SPP. Customers were recruited for participation in the SPP on an opt-in basis and received significant participation credits if they agreed to join the pilot program. The SPP used prices applied to all of each customer's usage. If this rate structure were compulsory, it would not meet the likely short-term mass-market requirement (due to AB1X) of avoiding changes to Tier 1 and Tier 2 rates. However, PG&E believes the results from the prices tested in the SPP can be used as good proxies for the expected long-term benefits of dynamic electric tariffs.

For the purposes of this update filing, PG&E has considered alternatives to the SPP rate design that could be used to implement TOU and CPP pricing for residential electric customers to potentially address AB1X constraints. PG&E has also examined cases that include revenue-neutral “hedge premiums” and “demand response participation” rate credits, for the purpose of achieving increased participation levels on a voluntary basis.

The first alternative that PG&E has considered would set revenue-neutral CPP and on-peak TOU price premiums and offsetting off-peak price credits, but would apply these price signals only to Tier 3 and Tier 4 electric usage. This scenario would also include per-kWh “hedge premiums” applicable to all Tier 3 and Tier 4 usage for those customers who do not choose to accept assignment to a demand response tariff. The incremental hedge premium revenue would be used to fund offsetting per-kWh rate credits for all Tier 3 and Tier 4 usage of those customers who do accept assignment to a demand response tariff. This rate design alternative would have the advantage of being completely transparent to any customer with only Tier 1 and Tier 2 usage on a given month’s bill, because such a customer would experience no change in their bill as a result of opting-in to the CPP program. However, it would have the possible disadvantage of significantly muting TOU and CPP price signals for the large number of customers who have little or no upper-tier electric usage.

The second rate design alternative that PG&E considered would apply revenue-neutral CPP and on-peak TOU price premiums and offsetting off-peak price credits to all electric usage, for those customers who accept assignment to the demand response tariff. Under this scenario, the per-kWh “hedge premium” would apply only to Tier 3 and Tier 4 usage for those customers who do not choose to participate in the demand response tariff, in order to comply with AB1X requirements. However, the offsetting participation credits would apply to all usage for those customers who do accept assignment to the demand response tariff. This rate design alternative would not be completely transparent to any customer with only Tier 1 and Tier 2 usage, although such customers could opt to continue to take service under the standard tariff, which would continue to conform to AB1X. This alternative would have the advantage of providing TOU and CPP price signals for all customers who are willing to accept them.

PG&E expects to address the issue of appropriate rate design for customers under AMI in additional detail in its dynamic rate design filing which it proposes to file in summer 2005, concurrently with its full AMI Project Application.

C. Bill Impacts for Demand-Response Tariffs

Summaries of PG&E's preliminary analysis of potential bill impact results for the two rate design alternatives described above are provided in Appendix E. The bill impact analysis provided in Appendix E includes the effects of both the net AMI-related electric rate recovery described in Section VII.A and the two rate design alternatives described in Section VII.B. The basic difference between these two scenarios is that the first alternative applies relatively "steep" price signals to upper-tier usage only. High-use customers who accept assignment to the tariff would have significant incentives to respond to the prices. The percent bill change that corresponds to a given usage reduction would increase as the customer gets further into the upper-tier levels of usage. The second alternative offers more balanced price signals for all customers at all usage levels.

Under a strictly revenue-neutral rate design, there will always be very nearly the same numbers of "winners" versus "losers." Adding a hedge premium (and using it to fund additional rate credits) changes this equation, and would make it possible to offer an at least marginally attractive rate even to those customers with somewhat worse-than-average load profiles.

VIII. DISCUSSION OF KEY MARKET, REGULATORY, AND FINANCING FACTORS THAT COULD AFFECT THE BUSINESS CASE ANALYSIS

PG&E's updated business case is subject to market, regulatory and business environment changes that could affect the results. While assumptions regarding costs and benefits are addressed in detail in sections III and IV above, 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 legislation could significantly affect the business case.[15] 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 ISO[16] will allow PG&E to count the demand response predicted from AMI for purposes of meeting PG&E's resource adequacy requirements. The demand response 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 business case analysis could be affected. Guidelines have been discussed at CPUC-sponsored resource adequacy workshops to determine the amounts of dependable demand response that can be counted to reduce procurement costs.[17] Since there has not yet been a final Commission decision on counting rules, the inputs and assumptions used in the demand response model are

[15] For example, PG&E is aware of three bills in the current legislative session – AB 1009, AB 1348, and SB 441 – each of which if passed into law could have an effect on AMI.

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

[17] For example, pursuant to Commission Decision 04-10-035, issued October 28, 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.)

inherently speculative and uncertain. However, given the improvement in the business case presented in this update analysis, the inherent uncertainty of demand response is less of a factor than it seemed on October 15, 2004.

CPUC's Avoided Cost proceeding: The valuation of demand response in the avoided cost proceeding, or other forums, could have a material impact on the ultimate business case results in this proceeding. The updated business case analysis presented here assumes a value of $85/ kW-year for demand response as specified in the July 21, 2004 ACR. However, PG&E believes that the avoided cost valuation of demand response is still an open question. PG&E will continue to monitor the avoided cost proceeding and other proceedings where the value of capacity is an issue.

Future CPUC AMI proceedings: The timing of decisions in a future AMI project 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 electric 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 estimating demand response. However, PG&E has considered some alternative rate designs, as discussed in section VII above.

Implementation of Community Choice Aggregation Program: The Commission opened Rulemaking 03-10-003 on October 2, 2003, to implement certain provisions of AB 117, which permits local governments to aggregate energy procurement on behalf of its citizens and businesses. The transfer of utility customers to Community Choice Aggregators (CCA) will change PG&E's load and resource plans, just as any other forecast variable related to expected changes in supply or demand. Utility resource plans will need to balance supply security with enough flexibility to accommodate many market contingencies in addition to those associated with the CCA program that may impact the business case.

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 assumed not 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 CCA program, expanded DA, municipalization efforts by other entities, or any other service territory or customer base shift (such as implementation of a core/non-core model for the electric market).

Continued operation of the ISO: 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.

Force majeure events: The updated business case does 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.

IX. COST RECOVERY

The November 24, 2004 ACR stated:

> Because deployment of advanced metering infrastructure is a significant cost and operational undertaking, as part of the cost recovery proposals the utilities will present in their applications, we are open to reviewing proposals about how the risks and rewards from deploying these systems should be allocated between ratepayers and shareholders. (p.5)

In this business case update, PG&E has not set forth its proposed AMI Project costs because the sufficiently-accurate costs for the project will not be known until after BAFO bids are obtained and analyzed. However, concurrent with this business case update, PG&E has filed an Application for cost recovery of the pre-deployment activities for AMI project costs needed to move forward and allow meters to be set beginning first quarter 2006 (Pre-deployment Application). The Application requests full cost recovery from gas and electric customers for $49 million of pre-deployment development costs. PG&E expects to recover through rates the capital investments and operating costs associated with implementing the pre-deployment requirements for an AMI Project.

In the AMI Pre-deployment Application PG&E requests authorization to incur costs up to $49 million and to book the actual expenses and the capital-related revenue requirement in the Advanced Metering Demand Response Account (AMDRA) and a proposed Gas Advanced Metering Account. Additionally, PG&E is requesting ultimate rate recovery, through the Distribution Revenue Adjustment Mechanism and the Core Fixed Cost Account, of those amounts, after a quarterly review verifying that the costs were spent on pre-deployment activities.

PG&E expects to recover the full cost of the AMI Project ultimately brought forth by

PG&E and approved by the Commission. In the full AMI Project Application, PG&E will allocate the costs among gas and electric customers and will seek rates to recover the full capital cost investment and on-going operating costs of the Project, less the Pre-deployment costs already authorized for recovery in rates. PG&E anticipates establishing a balancing account to ensure full recovery of the AMI Project costs.

X. CONCLUSION

PG&E is pleased to be able to present the preceding update to it AMI business case analysis and looks forward to filing its full AMI Project application in summer 2005.

Respectfully Submitted,

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By:______________________________________
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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: March 15, 2005

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, B8R, PO Box 770000, San Francisco, CA 94177.

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 March 15, 2005, I served a true copy of:

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

by electronic transmission to all parties on the official service list R.02-06-001 who provided e-mail addresses.

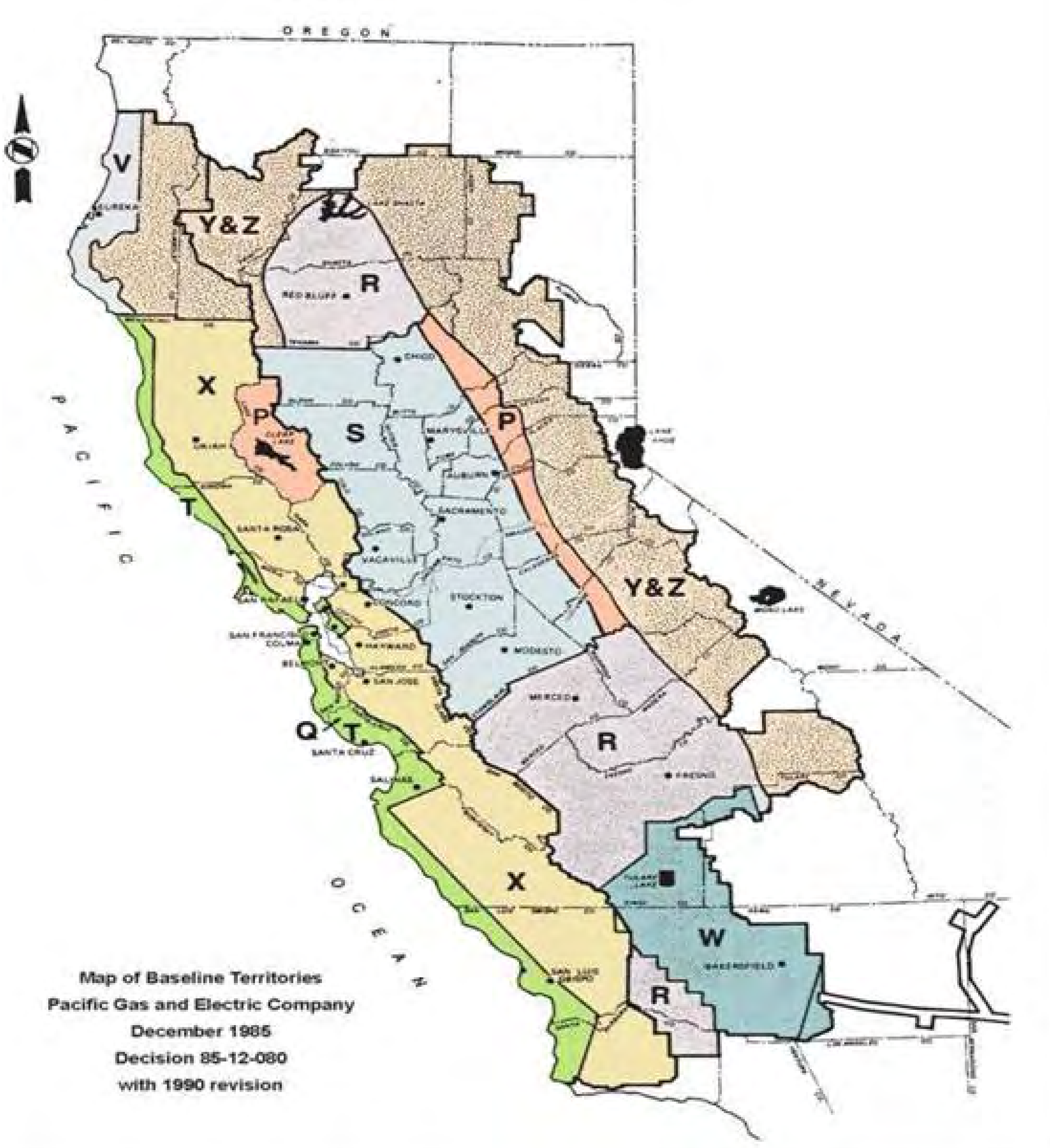
I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct and that this declaration was executed on March 15, 2005, at San Francisco, California.

KAREN THERESA ABALOS

APPENDIX A

PG&E Baseline Territories

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
Preferred Full-deployment Case
REDACTED

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Appendix B
Case Results
Preferred Full-deployment Case
REDACTED

Table B-1
Pacific Gas and Electric Company
AMI Full-deployment Case Results
(millions)

Case Summary	Rate Used	
Deployment	Full Deployment; 4.8 million electric – 4.1 million gas meters	
Deployment start and timeframe	1st Quarter 2006; 5 year deployment	
Operational Cost Summary		
Deployment Costs (PVRR)	Communication System	[redacted]
	Information technology and application	[redacted]
	Customer Services	
	Meter System and Installation	
	Management and Other Costs	
	Gas Service Impacts	
	TOTAL AMI Deployment Costs	$1,539
Operations and maintenance (PVRR)	Communication System	[redacted]
	Information technology and application	[redacted]
	Customer Services	
	Management and Other Costs	
	Gas Service Impacts	
	TOTAL Operations and Maintenance Costs	
TOTAL Incremental Costs		$1,947
Operational Benefits		
	Systems Operational Benefits	($919)
	Customer Service Benefits	($51)
	Demand Response Benefits	See Appendix D
	Management and Other Benefits	($568)
	TOTAL Operational Benefits	($1,538)
	Operational Gap, PVRR, Utility Cost Test	$409
	Operational Gap, PVRR, Total Resource Cost Test	$168

Figure B-1
Pacific Gas and Electric Company
Full-deployment Demand Response

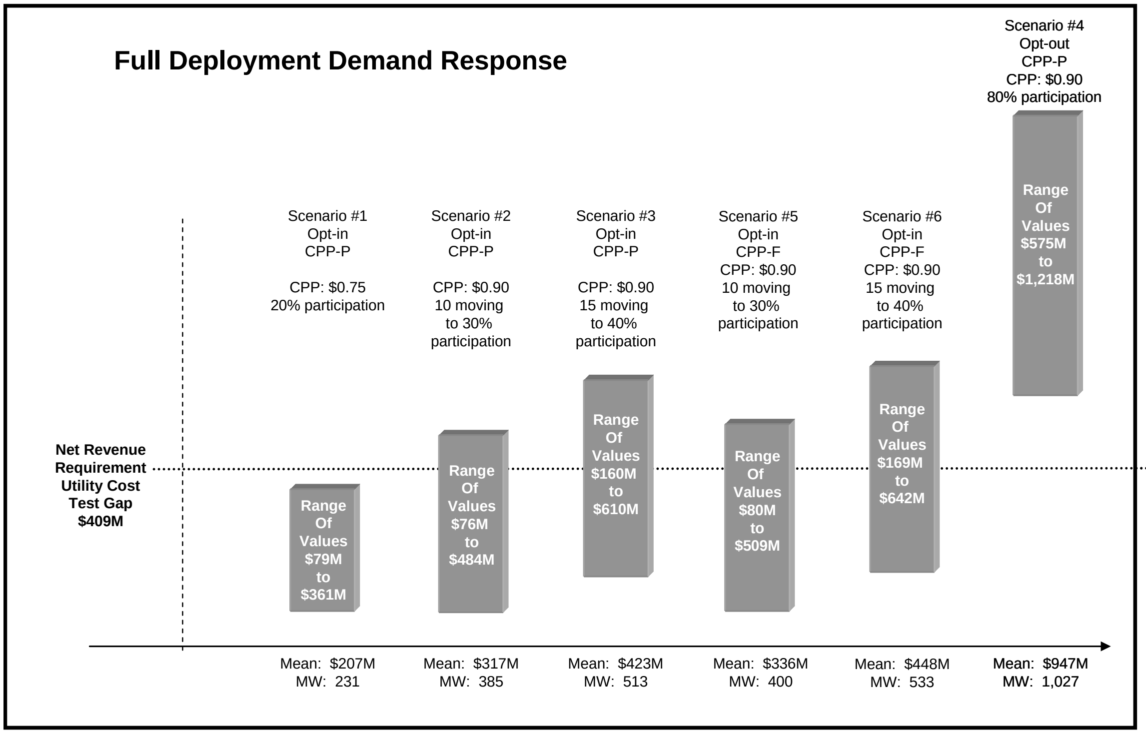

Table B-2
Pacific Gas and Electric Company
Cost Components (Deployment)

ACR Category	Description of Category	PVRR (millions)	Reference
MS-12a	Cost of Maintaining Existing Metering Systems	$1,731	
C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$21	
	Total - Base Case	**$1,752**	

Cost Components (Deployment)			
Communication System			
C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	[redacted]	
C-10	Purchase network communications equipment and hardware	[redacted]	
Information Technology and Application			
I-2	Computing system implementation in data center (new hardware/software, IT security review & compliance)	[redacted]	
Customer Services			
CU-1	Customer records/billing and collections work associated with roll-out of meter change process	[redacted]	

ACR Category	Description of Category	PVRR (millions)	Reference
CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	[redacted]	
Meter System and Installation			
MS-3	Cost of purchasing meters, communications modules and related vendor support equipment & software	[redacted]	
Management and Other Costs			
M-3	Customers access to usage information through communications medium	[redacted]	
M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	[redacted]	
Gas Services Impacts			
GS-1	Gas Index/Module Purchases	[redacted]	
	Total - Cost Components (Deployment)	**$1,539**	

Cost Components (O&M)			
Communication System			
C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	[redacted]	
Information Technology and Application			
I-9	Aggregating, validating and creating billing determinant data for electric billing	[redacted]	
I-10	Contract administration and database management of public network connections	[redacted]	
I-15	Operating costs - retrieval and delivery of meter, maintenance & outage information systems data and alarms	[redacted]	
Customer Services			
CU-9	Customer support for internet based usage data communication	[redacted]	
Management and Other Costs			
M-14	Customer acquisition and marketing costs for new tariffs	[redacted]	
Gas Services Impacts			
GS-3	Replacement of gas meter module, battery purchases and replacement labor	[redacted]	
GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	[redacted]	
GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)		
	Total - Cost Components (O&M)	**$408**	
	Total - Cost Components (Deployment & O&M)	**$1,947**	

Table B-3
Pacific Gas and Electric Company
Benefit Components

ACR Category	Description of Category	PVRR (millions)	Reference
Benefit Components			
Systems Operations Benefits			
SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($714)	
SB-2	Field service savings (turn-ons / turn-offs) and lower need for pickup reads	$0	
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.	
SB-4	Phone Centers – Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($50)	

ACR Category	Description of Category	PVRR (millions)	Reference
SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($10)	
SB-6	Outage management benefits (momentary checking for PG&E)	($133)	
SB-7	Better meter functionality / equipment modernization	($6)	Note 1
SB-8	Remote service connect / disconnect	N.Q.	Note 2
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.	
SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and when they need to be replaced/repaired	($6)	
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.	N.Q.	
SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	
SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	
Customer Service Benefits			
CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	
CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	Note 3
CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($45)	
CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	
CB-6	Customer rate choice / new rate options	N.Q.	Note 4
CB-7	Customized billing date	N.Q.	
CB-8	Energy Information to customer can assist in managing loads	N.Q.	Note 5
CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	
CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($6)	
CB-11	On-line bill presentment with hourly data / more timely and accurate information about electricity / info access	N.Q.	Note 6
CB-12	Lower customer bills	N.Q.	
CB-13	Value to customers of more timely & accurate bills	N.Q.	

Table B-4
Pacific Gas and Electric Company
Demand Response Benefits

ACR Category	Description of Category	PVRR (millions)	Reference
Demand Response Benefits			
DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions		
DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.		
DR-3	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies	N.Q.	Note 7
DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)		

ACR Category	Description of Category	PVRR (millions)	Reference
Management and Other Benefits			
MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)	($7)	
MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
MB-3	Reduced battery replacement / calendar resets / meter programming	($62)	
MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	($1)	
MB-5	Summary billing cash flow benefits (existing customers)	($35)	
MB-6	Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	
MB-7	Possible new rev source / new business ventures / new products & services/web based interval & power-quality data	N.Q.	
MB-8	May facilitate ability to obtain GPS reads during meter deployment-improving Franchise & Utility Users Tax processes	N.Q.	Note 8
MB-9	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs	N.Q.	
MB-10	Potential for tax savings from federal investment tax credits	N.Q.	
Other Benefits			
MS-9	Salvage/Disposal process for removed meters	($1)	
XB-1	Existing Meter Tax write-off	($8)	Note 9
XB-2	Post analysis period net benefits	($290)	Note 10
XB-3	Saved costs from migrating Interval Meter program to AMI	($62)	Note 11
XB-4	Other employee related costs	($103)	Note 12

Total - Benefits (before demand response)	**($1,538)**
Total - System Cost	**$1,947**
AMI Operational Gap	**$409**

Systems Operations Benefits

Note 1

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

PG&E has quantified the benefit associated with deferral of meter testing resulting from replacement of meters under AMI. However, since this business case assumes that all electric meters will still be electromechanical meters, PG&E has not assigned a value to improved meter accuracy. 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 2

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.

Customer Service Benefits

Note 3

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 4

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 5

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 6

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.

Demand Response Benefits

Note 7

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 8

MB-8 *May facilitate ability to obtain GPS reads during meter deployment-improving Franchise and 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 9

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 10

XB-2 *Post analysis period net benefits:*

PG&E added this benefit category. PG&E assumed that the AMI metering and 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 percent 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.

Note _11

XB -3 *Saved Costs From Migrating Interval Meter Program To AMI*

PG&E includes in the business case the cost savings from moving the current interval meter program, including meters with demand greater than 200 kW, to the AMI network infrastructure. The majority of the identified savings relates to data acquisition and interval billing processing.

Note _12

XB -4 *Other employee related costs*

Other employee related costs are expenses that are included as a burden on labor expenses or as an additional benefit to labor savings. The items included in this benefit are pensions, post-retirement medical and life insurance benefits, long-term disability, workers compensation expense, and other miscellaneous costs per employee.

TABLE B-5
PACIFIC GAS AND ELECTRIC COMPANY
MARCH 15, 2005
AMI PROJECT BUSINESS CASE UPDATE
ELECTRIC AND GAS REVENUE REQUIREMENTS

	2006	2007	2008	2009	2010	2011	2012	2013
Full Deployment - Electric								
AMI Incremental Revenue Requirements [1]	$58,264,362	$67,396,760	$100,259,990	$134,205,316	$154,030,028	$145,838,270	$142,154,556	$138,351,204
Plus:								
Expected O&M and A&G Reductions	-$7,887,336	-$16,577,041	-$23,632,937	-$38,068,036	-$49,862,607	-$55,314,091	-$57,258,866	-$59,110,212
Franchise and Uncollectibles	-$75,857	-$159,430	-$227,291	-$366,121	-$479,555	-$531,985	-$550,689	-$568,494
Expected Capital Reductions	-$729,513	-$7,461,672	-$24,261,685	-$39,032,208	-$52,940,886	-$60,060,372	-$62,288,328	-$63,941,507
Franchise and Uncollectibles	-$7,016	-$71,763	-$233,338	-$375,394	-$509,161	-$577,633	-$599,060	-$614,960
Net AMI Incremental RRQ	$49,564,640	$43,126,853	$51,904,740	$56,363,557	$50,237,818	$29,354,190	$21,457,613	$14,116,030
Full Deployment - Gas								
AMI Incremental Revenue Requirements	$43,162,520	$43,742,220	$63,019,328	$83,136,901	$96,742,753	$93,830,383	$93,481,807	$92,719,431
Plus:								
Expected O&M and A&G Reductions	-$197,918	-$1,856,869	-$5,119,404	-$8,305,813	-$11,135,472	-$12,589,622	-$13,154,432	-$13,663,200
Franchise and Uncollectibles	-$2,333	-$21,889	-$60,348	-$97,909	-$131,265	-$148,406	-$155,064	-$161,062
Expected Capital Reductions	-$497,030	-$5,335,010	-$18,241,257	-$29,446,580	-$40,233,212	-$45,964,223	-$47,755,374	-$49,067,376
Franchise and Uncollectibles	-$5,859	-$62,889	-$215,028	-$347,116	-$474,269	-$541,826	-$562,940	-$578,406
Net AMI Incremental RRQ	$42,459,380	$36,465,562	$39,383,291	$44,939,483	$44,768,534	$34,586,306	$31,853,997	$29,249,386

[1] Revenue Requirements without savings

TABLE B-5
PACIFIC GAS AND ELECTRIC COMPANY
MARCH 15, 2005
AMI PROJECT BUSINESS CASE UPDATE
ELECTRIC AND GAS REVENUE REQUIREMENTS
(CONTINUED)

	2014	2015	2016	2017	2018	2019	2020	2021
Full Deployment - Electric								
AMI Incremental Revenue Requirements [1]	$134,825,546	$131,423,671	$127,721,313	$124,142,442	$120,579,111	$116,755,421	$112,916,016	$105,616,791
Plus:								
Expected O&M and A&G Reductions	-$60,996,386	-$63,532,044	-$66,108,817	-$68,764,312	-$71,526,022	-$74,370,936	-$77,620,324	-$80,676,621
Franchise and Uncollectibles	-$586,635	-$611,022	-$635,804	-$661,343	-$687,904	-$715,265	-$746,516	-$775,910
Expected Capital Reductions	-$65,656,419	-$69,654,168	-$71,552,442	-$73,517,073	-$75,553,154	-$77,658,748	-$82,212,493	-$84,542,385
Franchise and Uncollectibles	-$631,453	-$669,901	-$688,158	-$707,053	-$726,635	-$746,886	-$790,681	-$813,089
Net AMI Incremental RRQ	$6,954,653	-$3,043,464	-$11,263,907	-$19,507,339	-$27,914,604	-$36,736,414	-$48,453,999	-$61,191,214
Full Deployment - Gas								
AMI Incremental Revenue Requirements	$92,202,879	$92,160,815	$99,111,235	$118,840,708	$121,452,389	$121,161,008	$104,481,985	$86,578,626
Plus:								
Expected O&M and A&G Reductions	-$14,185,531	-$14,968,115	-$15,516,569	-$16,081,259	-$16,666,744	-$17,269,938	-$18,158,842	-$18,811,031
Franchise and Uncollectibles	-$167,219	-$176,444	-$182,909	-$189,566	-$196,468	-$203,578	-$214,056	-$221,744
Expected Capital Reductions	-$50,434,108	-$53,715,986	-$55,247,399	-$56,836,088	-$58,484,072	-$60,191,740	-$63,948,884	-$65,845,184
Franchise and Uncollectibles	-$594,517	-$633,204	-$651,256	-$669,984	-$689,410	-$709,540	-$753,829	-$776,183
Net AMI Incremental RRQ	$26,821,503	$22,667,065	$27,513,100	$45,063,812	$45,415,695	$42,786,212	$21,406,374	$924,484

[1] Revenue Requirements without savings

TABLE B-6
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
FULL DEPLOYMENT CASE
FIRST FOUR YEARS OF REVENUE REQUIREMENT
ILLUSTRATIVE CLASS AVERAGE RATES

			2006		2007		2008		2009		
Line No.	Customer Class	Present Rate (c/kWh)	Proposed Rate (c/kWh)	Average Rate Change	Proposed Rate (c/kWh)	Average Rate Change	Proposed Rate (c/kWh)	Average Rate Change	Proposed Rate (c/kWh)	Average Rate Change	Line No.
1	Residential	12.83	12.91	0.08	12.90	0.07	12.91	0.09	12.92	0.09	1
2	Small L&P	15.01	15.10	0.09	15.09	0.08	15.10	0.09	15.11	0.10	2
3	Medium L&P	13.87	13.92	0.05	13.92	0.04	13.93	0.05	13.93	0.06	3
4	E-19 Class	11.27	11.32	0.04	11.31	0.04	11.32	0.05	11.32	0.05	4
5	Streetlights	15.20	15.36	0.15	15.34	0.13	15.37	0.16	15.38	0.18	5
6	Standby	13.65	13.68	0.03	13.68	0.03	13.68	0.03	13.69	0.04	6
7	Agriculture	11.91	12.00	0.09	11.98	0.08	12.00	0.09	12.01	0.10	7
8	E-20 Class	8.26	8.27	0.02	8.27	0.02	8.27	0.02	8.28	0.02	8
	E-20T	5.85	5.85	0.00	5.85	0.00	5.85	0.00	5.85	0.00	
	E-20P	9.12	9.14	0.02	9.13	0.02	9.14	0.02	9.14	0.02	
	E-20S	11.17	11.22	0.05	11.21	0.04	11.22	0.05	11.23	0.06	
9	**System Avg. Rate**	12.11	12.17	0.06	12.17	0.05	12.18	0.06	12.18	0.07	9

TABLE B-7
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
FULL DEPLOYMENT CASE
FIRST FOUR YEARS OF REVENUE REQUIREMENT
ILLUSTRATIVE CLASS AVERAGE RATES (3)

Line No.	Customer Class	Present Rate ($/therm)	2006 Proposed Rate ($/therm)	$ Change	2007 Proposed Rate ($/therm)	$ Change	2008 Proposed Rate ($/therm)	$ Change	2009 Proposed Rate ($/therm)	$ Change	Line No.
	Core Retail - Bundled (1)										
1	Residential	$1.117	$1.132	$0.015	$1.130	$0.013	$1.131	$0.014	$1.133	$0.016	1
2	Commercial, Small	1.082	1.094	0.012	1.092	0.010	1.093	0.011	1.094	0.013	2
3	Commercial, Large	0.899	0.904	0.005	0.903	0.004	0.904	0.004	0.904	0.005	3
	Core Retail - Transportation Only (2)										
4	Residential	0.386	0.400	0.015	0.398	0.013	0.399	0.014	0.401	0.016	4
5	Commercial, Small	0.359	0.371	0.012	0.369	0.010	0.370	0.011	0.371	0.013	5
6	Commercial, Large	0.201	0.206	0.005	0.205	0.004	0.206	0.004	0.206	0.005	6
	Noncore - Transportation Only (2)										
7	Industrial Distribution	0.120	0.120	0.000	0.120	0.000	0.120	0.000	0.120	0.000	7
8	Industrial Transmission	0.042	0.042	0.000	0.042	0.000	0.042	0.000	0.042	0.000	8
9	Industrial Backbone	0.024	0.024	0.000	0.024	0.000	0.024	0.000	0.024	0.000	9
10	Electric Generation	0.016	0.016	0.000	0.016	0.000	0.016	0.000	0.016	0.000	10
11	EG Backbone	0.001	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.000	11
	Wholesale - Transportation Only (2)										
12	Wholesale	0.017	0.017	0.000	0.017	0.000	0.017	0.000	0.017	0.000	12

(1) Bundled core rates include: i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.61479 per therm; ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(2) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

(3) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

Appendix C
Case Results
Partial-deployment Case
– Confidential –
Submitted pursuant to Public Utilities Code Section 583
REDACTED

TABLE OF CONTENTS

Appendix C
Case Results
Partial-deployment Case
– Confidential –
Submitted pursuant to Public Utilities Code Section 583
REDACTED

Table C-1
Pacific Gas and Electric Company
AMI Partial-deployment Case Results
(millions)

Case Summary	Rate Used	
Deployment	Partial Deployment; 1.9 million electric –1.8 million gas meters	
Deployment start and timeframe	1st Quarter 2006; 3 year deployment	
Operational Cost Summary		
Deployment Costs (PVRR)	Communication System	[redacted]
	Information technology and application	[redacted]
	Customer Services	[redacted]
	Meter System and Installation	[redacted]
	Management and Other Costs	[redacted]
	Gas Service Impacts	[redacted]
	TOTAL AMI Deployment Costs	$775
Operations and maintenance (PVRR)	Communication System	[redacted]
	Information technology and application	[redacted]
	Customer Services	[redacted]
	Management and Other Costs	[redacted]
	Gas Service Impacts	[redacted]
	TOTAL Operations and Maintenance Costs	$282
TOTAL Incremental Costs		$1,057
Operational Benefits		
	Systems Operational Benefits	($413)
	Customer Service Benefits	($21)
	Demand Response Benefits	See Appendix D
	Management and Other Benefits	($176)
	TOTAL Operational Benefits	($610)
	Operational Gap, PVRR, Utility Cost Test	$447
	Operational Gap, PVRR, Total Resource Cost Test	$301

Figure C-1
Pacific Gas and Electric Company
Partial-deployment Demand Response

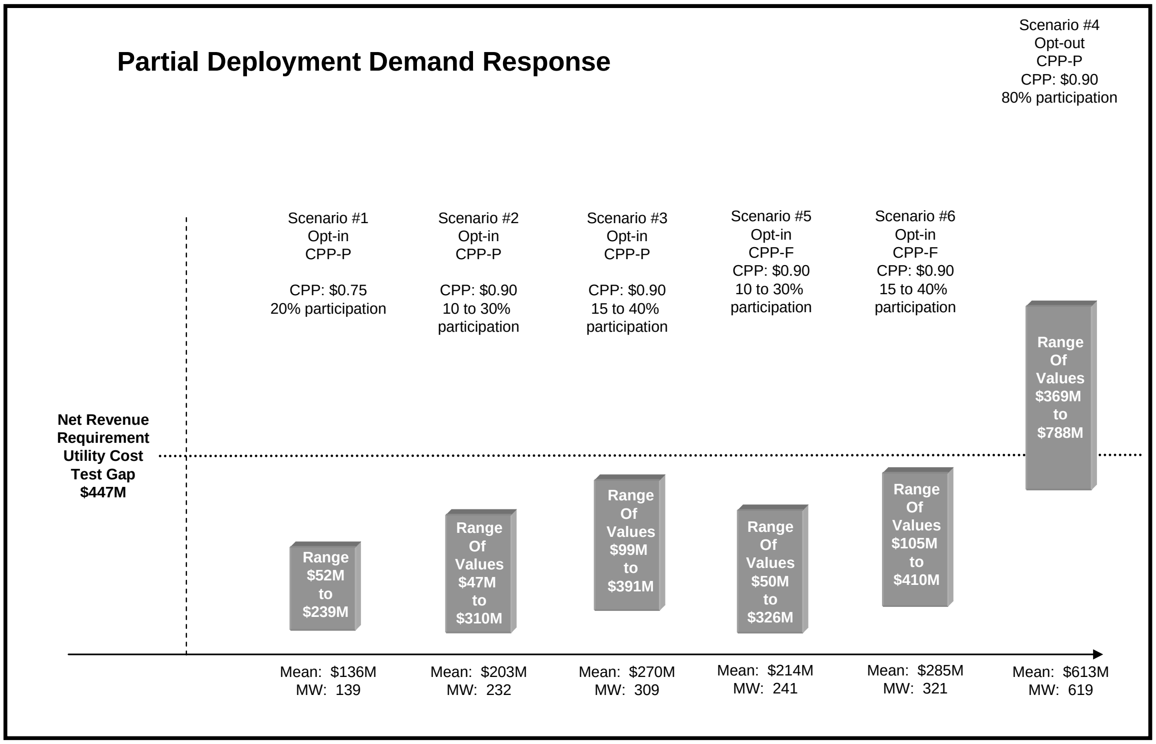

Table C-2
Pacific Gas and Electric Company
Cost Components (Deployment)

ACR Category	Description of Category	PVRR (millions)	Reference
MS-12a	Cost of Maintaining Existing Metering Systems	$1,731	
C-12a	Cost of Existing communication systems that take data from meters on monthly basis and turn it into bills	$21	
	Total - Base Case	**$1,752**	

Cost Components (Deployment)			
Communication System			
C-8a	Development of communications link from meters to data center, LAN/WAN/servers for storage & processing	[redacted]	
C-10	Purchase network communications equipment and hardware	[redacted]	
Information Technology and Application			
I-2	Computing system implementation in data center (new hardware/software, IT security review & compliance)	[redacted]	
Customer Services			
CU-1	Customer records/billing and collections work associated with roll-out of meter change process	[redacted]	

ACR Category	Description of Category	PVRR (millions)	Reference
CU-2	Increased call center activity during transition from existing to new rates /meter change appointments	[redacted]	
Meter System and Installation			
MS-3	Cost of purchasing meters, communications modules and related vendor support equipment & software	[redacted]	
Management and Other Costs			
M-3	Customers access to usage information through communications medium	[redacted]	
M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions	[redacted]	
Gas Services Impacts			
GS-1	Gas Index/Module Purchases	[redacted]	
	Total - Cost Components (Deployment)	**$775**	

Cost Components (O&M)			
Communication System			
C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment	[redacted]	
Information Technology and Application			
I-9	Aggregating, validating and creating billing determinant data for electric billing	[redacted]	
I-10	Contract administration and database management of public network connections	[redacted]	
I-15	Operating costs - retrieval and delivery of meter, maintenance & outage information systems data and alarms	[redacted]	
Customer Services			
CU-9	Customer support for internet based usage data communication	[redacted]	
Management and Other Costs			
M-14	Customer acquisition and marketing costs for new tariffs	[redacted]	
Gas Services Impacts			
GS-3	Replacement of gas meter module, battery purchases and replacement labor	[redacted]	
GS-5	Aggregation/Validation of monthly/hourly reads for gas billing	[redacted]	
GS-9	Performing atmospheric corrosion inspections (currently performed by meter readers)	[redacted]	
	Total - Cost Components (O&M)	**$282**	
	Total - Cost Components (Deployment & O&M)	**$1,057**	

Table C-3
Pacific Gas and Electric Company
Benefit Components

ACR Category	Description of Category	PVRR (millions)	Reference
Benefit Components			
Systems Operations Benefits			
SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)	($330)	
SB-2	Field service savings (turn-ons / turn-offs) and lower need for pickup reads	$0	
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.	
SB-4	Phone Centers – Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)	($20)	
SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change	($4)	

ACR Category	Description of Category	PVRR (millions)	Reference
SB-6	Outage management benefits (momentary checking for PG&E)	($54)	
SB-7	Better meter functionality / equipment modernization	($2)	Note 1
SB-8	Remote service connect / disconnect	N.Q.	Note 2
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.	
SB-10	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and when they need to be replaced/repaired	($2)	
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.	N.Q.	
SB-12	Ability to monitor customer self generation into system on a real time basis	N.Q.	
SB-13	Reduction in the amount of time to implement new rates and or load management programs.	N.Q.	
Customer Service Benefits			
CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”	Included in SB-1	
CB-2	Early detection of meter failures and distribution line stresses can reduce outages and improve customer service	N.Q.	
CB-3	May provide additional opportunity to inspect panel, reattachment of unsecured meter boxes, ID any unsafe conditions	N.Q.	Note 3
CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing	($18)	
CB-5	Customer energy profiles for EE / DR targeting (marketing)	N.Q.	
CB-6	Customer rate choice / new rate options	N.Q.	Note 4
CB-7	Customized billing date	N.Q.	
CB-8	Energy Information to customer can assist in managing loads	N.Q.	Note 5
CB-9	Enhanced billing options could be a source of revenue and increased customer satisfaction	N.Q.	
CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits	($3)	
CB-11	On-line bill presentment with hourly data / more timely and accurate information about electricity / info access	N.Q.	Note 6
CB-12	Lower customer bills	N.Q.	
CB-13	Value to customers of more timely & accurate bills	N.Q.	

Table C-4
Pacific Gas and Electric Company
Demand Response Benefits

ACR Category	Description of Category	PVRR (millions)	Reference
Demand Response Benefits			
DR-1	Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions		
DR-2	System reliability benefits (capacity buffer)- increased level of dispatchable load reductions could increase effective capacity margin and reduce loss of load probability.		
DR-3	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies	N.Q.	Note 7
DR-4	Avoided / deferred transmission and distribution (T&D) additions / upgrade costs (T&D)		
Management and Other Benefits			

ACR Category	Description of Category	PVRR (millions)	Reference
MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)	($3)	
MB-2	Reduced misc. support expenses (including office equipment and supplies)	Included in SB-1	
MB-3	Reduced battery replacement / calendar resets / meter programming	($25)	
MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity	($0)	
MB-5	Summary billing cash flow benefits (existing customers)	$0	
MB-6	Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes (indirect benefit)	N.Q.	
MB-7	Possible new rev source / new business ventures / new products & services/web based interval & power-quality data	N.Q.	
MB-8	May facilitate ability to obtain GPS reads during meter deployment-improving Franchise & Utility Users Tax processes	N.Q.	Note 8
MB-9	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs	N.Q.	
MB-10	Potential for tax savings from federal investment tax credits	N.Q.	
Other Benefits			
MS-9	Salvage/Disposal process for removed meters	($0)	
XB-1	Existing Meter Tax write-off	($4)	Note 9
XB-2	Post analysis period net benefits	($82)	Note 10
XB-3	Saved costs from migrating Interval Meter program to AMI	($25)	Note 11
XB-4	Other employee related costs	($36)	Note 12

	Total - Benefits (before demand response)	**($610)**
Total - System Cost		**$1,057**
AMI Operational Gap		**$447**

Systems Operations Benefits

Note 1

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

PG&E has quantified the benefit associated with deferral of meter testing resulting from replacement of meters under AMI. However, since this business case assumes that all electric meters will still be electromechanical meters, PG&E has not assigned a value to improved meter accuracy. 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 2

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.

<u>Customer Service Benefits</u>

<u>Note 3</u>

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.

<u>Note 4</u>

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.

<u>Note 5</u>

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.)

<u>Note 6</u>

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.

Demand Response Benefits

Note 7

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 8

MB-8 *May facilitate ability to obtain GPS reads during meter deployment-improving Franchise and 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 9

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 10

XB-2 *Post analysis period net benefits:*

PG&E added this benefit category. PG&E assumed that the AMI metering and 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 percent 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.

Note _11

XB -3 *Saved Costs From Migrating Interval Meter Program To AMI*

PG&E includes in the business case the cost savings from moving the current interval meter program, including meters with demand greater than 200 kW, to the AMI network infrastructure. The majority of the identified savings relates to data acquisition and interval billing processing.

Note _12

XB -4 *Other employee related costs*

Other employee related costs are expenses that are included as a burden on labor expenses or as an additional benefit to labor savings. The items included in this benefit are pensions, post-retirement medical and life insurance benefits, long-term disability, workers compensation expense, and other miscellaneous costs per employee

TABLE C-5
PACIFIC GAS AND ELECTRIC COMPANY
MARCH 15, 2005
AMI PROJECT BUSINESS CASE UPDATE
PARTIAL DEPLOYMENT CASE
ELECTRIC AND GAS REVENUE REQUIREMENTS

	2006	2007	2008	2009	2010	2011	2012	2013
Partial Deployment - Electric								
AMI Incremental Revenue Requirements [1]	$56,791,911	$62,758,721	$77,811,729	$69,444,982	$68,084,381	$66,496,247	$65,246,241	$63,812,744
Plus:								
Expected O&M and A&G Reductions	-$3,586,971	-$10,869,019	-$15,544,807	-$18,932,322	-$20,037,844	-$20,719,442	-$21,103,749	-$21,855,055
Franchise and Uncollectibles	-$34,498	-$104,533	-$149,503	-$182,082	-$192,715	-$199,270	-$202,966	-$210,192
Expected Capital Reductions	-$505,928	-$3,328,194	-$10,223,948	-$19,836,828	-$22,543,006	-$23,155,127	-$23,791,853	-$24,453,781
Franchise and Uncollectibles	-$4,866	-$32,009	-$98,329	-$190,781	-$216,808	-$222,695	-$228,819	-$235,185
Net AMI Incremental RRQ	$52,659,648	$48,424,966	$51,795,143	$30,302,968	$25,094,008	$22,199,712	$19,918,855	$17,058,532
Partial Deployment - Gas								
AMI Incremental Revenue Requirements	$41,276,921	$40,155,897	$52,101,318	$48,651,722	$48,839,700	$48,499,492	$48,470,610	$48,231,523
Plus:								
Expected O&M and A&G Reductions	-$170,102	-$1,423,309	-$3,304,383	-$4,860,606	-$5,324,702	-$5,524,887	-$5,734,191	-$5,951,793
Franchise and Uncollectibles	-$2,005	-$16,778	-$38,952	-$57,297	-$62,768	-$65,127	-$67,595	-$70,160
Expected Capital Reductions	-$421,607	-$2,940,834	-$9,732,943	-$18,884,165	-$21,460,379	-$22,043,103	-$22,649,250	-$23,279,389
Franchise and Uncollectibles	-$4,970	-$34,667	-$114,732	-$222,607	-$252,975	-$259,844	-$266,989	-$274,417
Net AMI Incremental RRQ	$40,678,236	$35,740,309	$38,910,308	$24,627,048	$21,738,876	$20,606,530	$19,752,585	$18,655,764

[1] Revenue Requirements without savings

TABLE C-5
PACIFIC GAS AND ELECTRIC COMPANY
MARCH 15, 2005
AMI PROJECT BUSINESS CASE UPDATE
PARTIAL DEPLOYMENT CASE
ELECTRIC AND GAS REVENUE REQUIREMENTS
(CONTINUED)

	2014	2015	2016	2017	2018	2019	2020	2021
Partial Deployment - Electric								
AMI Incremental Revenue Requirements [1]	$62,464,162	$61,123,900	$59,580,125	$58,050,274	$56,498,485	$54,817,658	$53,127,360	$48,059,191
Plus:								
Expected O&M and A&G Reductions	-$22,794,179	-$23,871,450	-$24,836,505	-$25,829,690	-$26,862,470	-$27,926,360	-$29,159,473	-$30,302,811
Franchise and Uncollectibles	-$219,224	-$229,584	-$238,866	-$248,418	-$258,351	-$268,583	-$280,442	-$291,438
Expected Capital Reductions	-$25,142,113	-$26,793,061	-$27,562,324	-$28,359,494	-$29,185,568	-$30,040,843	-$31,948,229	-$32,897,024
Franchise and Uncollectibles	-$241,805	-$257,683	-$265,082	-$272,748	-$280,693	-$288,919	-$307,263	-$316,388
Net AMI Incremental RRQ	$14,066,842	$9,972,122	$6,677,348	$3,339,923	-$88,597	-$3,707,046	-$8,568,047	-$15,748,470
Partial Deployment - Gas								
AMI Incremental Revenue Requirements	$48,016,309	$47,948,418	$55,866,856	$74,449,647	$59,264,931	$46,626,278	$46,400,490	$43,655,013
Plus:								
Expected O&M and A&G Reductions	-$6,175,244	-$6,523,038	-$6,758,426	-$7,000,788	-$7,251,960	-$7,510,725	-$7,908,244	-$8,188,388
Franchise and Uncollectibles	-$72,794	-$76,894	-$79,668	-$82,525	-$85,486	-$88,536	-$93,222	-$96,525
Expected Capital Reductions	-$23,934,664	-$25,506,325	-$26,238,644	-$26,997,531	-$27,783,932	-$28,598,132	-$30,413,916	-$31,317,145
Franchise and Uncollectibles	-$282,142	-$300,669	-$309,301	-$318,247	-$327,517	-$337,115	-$358,519	-$369,166
Net AMI Incremental RRQ	$17,551,466	$15,541,493	$22,480,816	$40,050,556	$23,816,035	$10,091,769	$7,626,587	$3,683,788

[1] Revenue Requirements without savings

TABLE C-6
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC DEPARTMENT
PARTIAL DEPLOYMENT CASE
FIRST FOUR YEARS OF REVENUE REQUIREMENT
ILLUSTRATIVE CLASS AVERAGE RATES

			2006		2007		2008		2009		
Line No.	Customer Class	Present Rate (c/kWh)	Proposed Rate (c/kWh)	Average Rate Change	Proposed Rate (c/kWh)	Average Rate Change	Proposed Rate (c/kWh)	Average Rate Change	Proposed Rate (c/kWh)	Average Rate Change	Line No.
1	Residential	12.83	12.91	0.09	12.91	0.08	12.91	0.08	12.88	0.05	1
2	Small L&P	15.01	15.10	0.09	15.10	0.09	15.10	0.09	15.07	0.05	2
3	Medium L&P	13.87	13.93	0.05	13.92	0.05	13.93	0.05	13.90	0.03	3
4	E-19 Class	11.27	11.32	0.05	11.31	0.04	11.32	0.05	11.30	0.03	4
5	Streetlights	15.20	15.37	0.16	15.36	0.15	15.37	0.16	15.30	0.09	5
6	Standby	13.65	13.69	0.03	13.68	0.03	13.68	0.03	13.67	0.02	6
7	Agriculture	11.91	12.00	0.10	11.99	0.09	12.00	0.09	11.96	0.06	7
8	E-20 Class	8.26	8.28	0.02	8.27	0.02	8.27	0.02	8.27	0.01	8
	E-20T	5.85	5.85	0.00	5.85	0.00	5.85	0.00	5.85	0.00	
	E-20P	9.12	9.14	0.02	9.14	0.02	9.14	0.02	9.13	0.01	
	E-20S	11.17	11.22	0.05	11.22	0.05	11.22	0.05	11.20	0.03	
9	**System Avg. Rate**	12.11	12.18	0.06	12.17	0.06	12.18	0.06	12.15	0.04	9

TABLE C-7
PACIFIC GAS AND ELECTRIC COMPANY
GAS DEPARTMENT
PARTIAL DEPLOYMENT CASE
FIRST FOUR YEARS OF REVENUE REQUIREMENT
ILLUSTRATIVE CLASS AVERAGE RATES (3)

Line No.	Customer Class	Present Rate ($/therm)	2006 Proposed Rate ($/therm)	$ Change	2007 Proposed Rate ($/therm)	$ Change	2008 Proposed Rate ($/therm)	$ Change	2009 Proposed Rate ($/therm)	$ Change	Line No.
	Core Retail - Bundled (1)										
1	Residential	$1.117	$1.131	$0.014	$1.130	$0.012	$1.131	$0.013	$1.126	$0.008	1
2	Commercial, Small	1.082	1.093	0.012	1.092	0.010	1.093	0.011	1.089	0.007	2
3	Commercial, Large	0.899	0.904	0.004	0.903	0.004	0.904	0.004	0.902	0.003	3
	Core Retail - Transportation Only (2)										
4	Residential	0.386	0.400	0.014	0.398	0.012	0.399	0.013	0.394	0.009	4
5	Commercial, Small	0.359	0.370	0.012	0.369	0.010	0.370	0.011	0.366	0.007	5
6	Commercial, Large	0.201	0.206	0.004	0.205	0.004	0.205	0.004	0.204	0.003	6
	Noncore - Transportation Only (2)										
7	Industrial Distribution	0.120	0.120	0.000	0.120	0.000	0.120	0.000	0.120	0.000	7
8	Industrial Transmission	0.042	0.042	0.000	0.042	0.000	0.042	0.000	0.042	0.000	8
9	Industrial Backbone	0.024	0.024	0.000	0.024	0.000	0.024	0.000	0.024	0.000	9
10	Electric Generation	0.016	0.016	0.000	0.016	0.000	0.016	0.000	0.016	0.000	10
11	EG Backbone	0.001	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.000	11
	Wholesale - Transportation Only (2)										
12	Wholesale	0.017	0.017	0.000	0.017	0.000	0.017	0.000	0.017	0.000	12

(1) Bundled core rates include: i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.61479 per therm; ii) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and iii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Actual procurement rate changes monthly.

(2) Transportation Only rates include: i) a transportation component that recovers customer class charges, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and ii) where applicable, a gas public purpose program surcharge that recovers the costs of low income California Alternate Rates for Energy (CARE), low income energy efficiency, customer energy efficiency, Research Development and Demonstration program and BOE/CPUC Admin costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's citygate/local transmission system.

(3) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage.

APPENDIX E

Preliminary Analysis of Initial Residential Rate Design Alternatives

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX E: PRELIMINARY ANALYSIS OF AMI RATE DESIGN ALTERNATIVES
CASE 1: TOU/CPP PRICES APPLY ONLY TO UPPER-TIER USE

Total Bills -- Charges/Credits Only Apply Over 130% of Baseline

	Monthly Bill Projections	Usage Level (kWh per summer billing month)				
		350	650	1000	1400	2000
Base Case	Current Rates:	$46	$84	$155	$243	$375
Bills calculated	"Best" Profile:	$46	$76	$124	$185	$278
under test rates	"Good" Profile:	$46	$79	$136	$208	$315
for customers	Avg. Profile:	$46	$83	$150	$233	$358
with indicated	"Poor" Profile:	$46	$87	$163	$258	$401
load profiles.	"Worst" Profile:	$46	$90	$177	$284	$443
Opt-out bill (with AMI+hedge cost)	Opt-Out Bills:	$46	$86	$162	$255	$395
	No. of Bills:	58%	22%	13%	6%	1%

Bill Components -- Charges/Credits Only Apply Over 130% of Baseline

Detail for calculation of monthly bills:	Monthly Bill Projections	Usage Level (kWh per summer billing month)				
		350	650	1000	1400	2000
All customers	Current Rates:	$46	$84	$155	$243	$375
All customers	AMI RRQ Cost:	$0	$0	$2	$3	$5
AMI participants	TOU/CPP Charges/Credits:					
net effect of CPP	"Best" Profile:	$0	-$7	-$26	-$48	-$80
and TOU charges	"Good" Profile:	$0	-$4	-$14	-$25	-$43
and credits by	Avg. Profile:	$0	$0	$0	$0	$0
load profile type	"Poor" Profile:	$0	$4	$14	$25	$43
(see next page)	"Worst" Profile:	$0	$7	$28	$51	$85
AMI participants	Opt-In Credit:	$0	-$2	-$7	-$13	-$22
Non-participants	Opt-Out Chrg:	$0	$1	$5	$9	$15

Notes:

1. Assumed AMI RRQ Cost: 0.10 cents per kWh, if applied to all electric use, but is set at equivalent rate: 0.37 cents per kWh for upper-tier usage only.

2. Projected TOU/CPP Charges/Credits are charges for on-peak TOU and CPP period usage, net of credits applied to off-peak usage. *TOU/CPP charges and credits apply only to usage above 130% of Baseline.* See next page for assumed charges/credits.

3. Opt-In credits and Opt-Out charges are set by fixing difference between effective charges for upper-tier use at 2.5 cents per kWh and assumes 40% of total upper-tier usage will be usage by customers who choose assignment to TOU/CPP.

4. Resulting Opt-In Credit of 1.5 cents and Opt-Out Charge of 1.0 cents per kWh are applied only to usage above 130% of Baseline.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX E: PRELIMINARY ANALYSIS OF AMI RATE DESIGN ALTERNATIVES
CASE 1: TOU/CPP PRICES APPLY ONLY TO UPPER-TIER USE

Usage Strata For Preliminary Study	Usage by Tier	Usage Level (kWh per month) 350	650	1000	1400	2000
Usage by tier, based on 400 kWh/month baseline allowance	Tier 1	350	400	400	400	400
	Tier 2	0	120	120	120	120
	Tier 3	0	130	280	280	280
	Tier 4	0	0	200	600	1200
Approximate number of customer bills with indicated usage level	Over 130%	0%	20%	48%	63%	74%
	No. of Cust.	58%	22%	13%	6%	1%
	Avg Use:	580	kWh/mo			
	% Over 130:	27%	total use			

Descriptive statistics for the preliminary customer use strata used for analysis.

Bill Calculations Current Rates	Current Rates	Current Bills Under 1/1/2005 Rates 350	650	1000	1400	2000
Details for calculation of current bills under January 1, 2005 rates	$0.11430	$45.72	$45.72	$45.72	$45.72	$45.72
	$0.12989	$0.00	$15.59	$15.59	$15.59	$15.59
	$0.17821	$0.00	$23.17	$49.90	$49.90	$49.90
	$0.21964	$0.00	$0.00	$43.93	$131.78	$263.57
	Current Bill:	$45.72	$84.47	$155.13	$242.99	$374.77
	Avg. Rate:	13.06	13.00	15.51	17.36	18.74

TOU/CPP Overlays *Average Profile*	TOU/CPP Over 130%	TOU/CPP Bill Changes ("Average" Profile) 350	650	1000	1400	2000
CPP Adder:	$1.00	$0.00	$5.20	$19.20	$35.20	$59.20
TOU Adder:	$0.25	$0.00	$5.20	$19.20	$35.20	$59.20
Off-Pk Credit:	-$0.10	$0.00	-$10.40	-$38.40	-$70.40	-$118.40
Net Change:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Load Profiles For Preliminary Study	Load Profile Assumptions	Assumed Load Shares for TOU/CPP Periods Best	Good	Average	Poor	Worst
Assumed shares of total summer usage by TOU/CPP period	CPP Use:	1.0%	2.5%	4.0%	5.5%	7.0%
	TOU Use:	10.0%	12.5%	16.0%	19.5%	23.0%
	Off-Peak:	89.0%	85.0%	80.0%	75.0%	70.0%
	Total Use:	100.0%	100.0%	100.0%	100.0%	100.0%
	No. of Cust.	5%	20%	50%	20%	5%

Note: These load shape assumptions are initial estimates developed for purpose of preparing preliminary analysis. This information will be updated using more complete data from entire CLRP sample population for Summer 2005 AMI Rate Design application.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX E: PRELIMINARY ANALYSIS OF AMI RATE DESIGN ALTERNATIVES
CASE 2: TOU/CPP PRICES APPLY TO ALL USAGE

Total Bills -- Charges/Credits Apply To All Usage (exc. Opt-Out)

	Monthly Bill Projections	Usage Level (kWh per summer billing month)				
		350	650	1000	1400	2000
Base Case	Current Rates:	$46	$84	$155	$243	$375
Bills calculated under test rates for customers with indicated load profiles.	"Best" Profile:	$36	$67	$129	$208	$325
	"Good" Profile:	$40	$74	$139	$222	$345
	Avg. Profile:	$44	$81	$151	$238	$368
	"Poor" Profile:	$48	$89	$162	$254	$391
	"Worst" Profile:	$52	$96	$174	$270	$414
Opt-out bill (with AMI+hedge cost)	Opt-Out Bills:	$46	$87	$164	$259	$402
	No. of Bills:	58%	22%	13%	6%	1%

Bill Components -- Charges/Credits Apply To All Usage (except Opt-Out)

Detail for calculation of monthly bills:	Monthly Bill Projections	Usage Level (kWh per summer billing month)				
		350	650	1000	1400	2000
All customers	Current Rates:	$46	$84	$155	$243	$375
All customers	AMI RRQ Cost:	$0	$0	$2	$3	$5
AMI participants	TOU/CPP Charges/Credits:					
net effect of CPP and TOU charges and credits by load profile type (see next page)	"Best" Profile:	-$8	-$14	-$22	-$30	-$43
	"Good" Profile:	-$4	-$7	-$12	-$16	-$23
	Avg. Profile:	$0	$0	$0	$0	$0
	"Poor" Profile:	$4	$7	$12	$16	$23
	"Worst" Profile:	$8	$15	$23	$32	$46
AMI participants	Opt-In Credit:	-$2	-$4	-$6	-$8	-$12
Non-participants	Opt-Out Chrg:	$0	$2	$7	$13	$22

Notes:

1. Assumed AMI RRQ Cost: 0.10 cents per kWh, if applied to all electric use, but is set at equivalent rate: 0.37 cents per kWh for upper-tier usage only.

2. Projected TOU/CPP Charges/Credits are charges for on-peak TOU and CPP period usage, net of credits applied to off-peak usage. *TOU/CPP charges and credits apply to all usage.* See next page for assumed TOU/CPP period charge and credit rates.

3. Opt-In credits and Opt-Out charges are set by fixing difference between effective charges for ***all usage*** at 1.0 cents per kWh and assumes 40% of total electricity usage will be usage by customers who choose assignment to TOU/CPP.

4. Resulting Opt-In Credit of 0.6 cents applies to all use, Opt-Out Charge 1.5 cents per kWh applies only to Tier 3 and Tier 4 usage.

PACIFIC GAS AND ELECTRIC COMPANY
APPENDIX E: PRELIMINARY ANALYSIS OF AMI RATE DESIGN ALTERNATIVES
CASE 2: TOU/CPP PRICES APPLY TO ALL USAGE

Usage Strata For Preliminary Study	Usage by Tier	Usage Level (kWh per month)				
		350	650	1000	1400	2000
Usage by tier, based on 400 kWh/month baseline allowance	Tier 1	350	400	400	400	400
	Tier 2	0	120	120	120	120
	Tier 3	0	130	280	280	280
	Tier 4	0	0	200	600	1200
Approximate number of customer bills with indicated usage level	Over 130%	0%	20%	48%	63%	74%
	No. of Cust.	58%	22%	13%	6%	1%

Avg Use:	580	kWh/mo
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Descriptive statistics for the preliminary customer use strata used for analysis.

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Details for calculation of current bills under January 1, 2005 rates	$0.11430	$45.72	$45.72	$45.72	$45.72	$45.72
	$0.12989	$0.00	$15.59	$15.59	$15.59	$15.59
	$0.17821	$0.00	$23.17	$49.90	$49.90	$49.90
	$0.21964	$0.00	$0.00	$43.93	$131.78	$263.57
	Current Bill:	$45.72	$84.47	$155.13	$242.99	$374.77
	Avg. Rate:	13.06	13.00	15.51	17.36	18.74

TOU/CPP Overlays ***Average Profile***	TOU/CPP All Usage	TOU/CPP Bill Changes ("Average" Profile)				
		350	650	1000	1400	2000
CPP Adder:	$0.40	$5.60	$10.40	$16.00	$22.40	$32.00
TOU Adder:	$0.10	$5.60	$10.40	$16.00	$22.40	$32.00
Off-Pk Credit:	-$0.04	-$11.20	-$20.80	-$32.00	-$44.80	-$64.00
Net Change:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Load Profiles For Preliminary Study	Load Profile Assumptions	Assumed Load Shares for TOU/CPP Periods				
		Best	Good	Average	Poor	Worst
Assumed shares of total summer usage by TOU/CPP period	CPP Use:	1.0%	2.5%	4.0%	5.5%	7.0%
	TOU Use:	10.0%	12.5%	16.0%	19.5%	23.0%
	Off-Peak:	89.0%	85.0%	80.0%	75.0%	70.0%
	Total Use:	100.0%	100.0%	100.0%	100.0%	100.0%
	No. of Cust.	5%	20%	50%	20%	5%

Note: These load shape assumptions are initial estimates developed for purpose of preparing preliminary analysis. This information will be updated using more complete data from entire CLRP sample population for Summer 2005 AMI Rate Design application.