DRAFT REPORT

Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure
(R.02-06-001)

April 14, 2004

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Section 1 - Overview and Summary of Recommendations

This report summarizes proposals and recommendations from Working Group 3 members (WG3) on the analysis framework to be used for the analysis of the costs and benefits of deploying an Advanced Metering Infrastructure (AMI) in the service territories of California's three major investor owned utilities: Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric (Joint Utilities). These recommendations are based on WG3 input, staff analysis, and previous guidance from the California Public Utilities Commission (Commission.) In most cases, agency staff supports the recommended functional definitions and framework provided by the functional and cost benefit subcommittees that were created through the Working Group 3 process.[1] In some cases, where no working group products are available, agency staff recommends common definitions or assumptions for use in developing the business case scenarios. Most of these recommendations were discussed in the AMI scenario development and demand response quantification workshops on March 29 and 30, 2004.

Staff believes the use of these common assumptions and formats will provide the Commission with the necessary cost/benefit analysis information to make a determination in this case and will also aid other parties by facilitating the use of common terms and methodologies to be used by the respondent utilities in their filings. We would like to thank all of the members of Working Group 3 for their hard and cooperative work in producing a common analysis framework that will facilitate the review and resolution of these issues.

[1] The subcommittee reports of the functional specification and benefit cost working groups are attached to this report as Appendices A - D.

Section 2 - Introduction and Background

The phase 2 Assigned Commissioner's Ruling and Scoping Memo (phase 2 memo) in Rulemaking (R.02-06-001) on policies and practices for advance metering, demand response, and dynamic pricing was issued on November 24, 2003. The focus of the Phase 2 Rulemaking is developing the analysis framework for advance metering infrastructure (AMI) business case. The Commission directed parties to file their AMI cost/benefit proposals by December 22, 2003, which needed to include: a list of the AMI costs and benefits categorized as short-term, long-term, and out-of-scope; proposals for measuring these costs and benefits; and AC cycling as a potential metering interface. On January 6, 2004, parties[2] filed their AMI cost/benefit proposals.

The phase 2 memo also established that the AMI business case framework would be analyzed/developed through the working group process. The WG3 moderator was directed to hold a public workshop to discuss the cost and benefits that needed to be considered in the AMI business case analysis. Three different perspectives needed to be considered in the analysis - utility, customer, and societal perspectives; and the costs benefits described in Appendix A of the Commission's September 19, 2004 Ruling.

The AMI analysis framework workshop was held on January 28, 2004. Parties were given the opportunity to present their AMI costs and benefits filings, which was followed by a discussion of the similarities and differences between parties' filings − assumptions used for system functionalities and rate structures. After some discussion the working agreed that more specificity and policy guidance was needed on the functionalities, and rate structures the AMI system needed to support, which were highlighted as some of the main drivers for designing and costing out the AMI system. Parties requested additional policy guidance from the Commission in these areas. In the mean time two subcommittees were created (an AMI system functionalities subcommittee and a cost/benefit subcommittee) to work on developing a more standard list of cost/benefit categories and AMI applications/functionalities. The work products from these subcommittees are discussed in Sections 3 and 4 of this report, and form the basis for the minimum AMI applications and functionalities for the AMI framework recommendations.

A Joint Assigned Commissioner and Administrative Law Judge Ruling was issued on February 19, 2004, which provided additional policy guidance on the system functionalities, rate structures, and customer classes that needed to be included in the AMI business case analysis. The Commission provided the following policy guidance:

1. The AMI system should provide the metering and communications capability to economically support a wide variety of rate and associated service options and maximize the amount of demand response cost-effectively.
2. Analyze an AMI system that supports a wide variety of potential rate structures and customer service options that the Commission may approve over the useful life of the AMI system.
3. Costs and benefits for all customer classes need to be included in the analysis.

[2] Coalition of California Utility Employees (CUE), California Consumer Empowerment Alliance (CCEA), The Utility Reform Network (TURN), Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE)

More specificity on the dynamic rates and AMI system functionalities are discussed in the Section 3 and 4 of this report.

Two additional workshops were held on March 29 and 30 of 2004. The first workshop focused on developing common set of definitions and assumptions for analyzing partial and full AMI deployment scenarios for the business case analysis. The second workshop focused on developing methodologies for quantifying and valuing demand response for annual impacts, during peak hours, and system emergencies for the business case.

Section 3 - Customer Service, Billing, and Rate Choice Applications that must be Supported in the Advanced Metering Infrastructure Analysis

This section provides staff recommendations for the minimum applications and derivative functional specifications that should be included in the AMI benefit cost analysis. These minimum specifications are based on recommendations from the WG3 functional subcommittee[3], discussions at the March 29, 2004 scenario development workshop, and previous policy direction from the CPUC.

AMI system functionalities and cost determinants:

The existing utility metering technology does not provide either the data recording or communication capabilities needed to support the dynamic rates and customer service options the Commission specified in its September 19, 2004 Ruling (higher levels of customer services or a level of system operating flexibility compatible with today's energy environment.) Current tariff offerings therefore cannot reflect the time-varying costs of providing electricity service. In addition, customer billing and information services have changed little over the last 50 years, limiting the information tools necessary to improve customer understanding or management of energy costs.

Implementation of new AMI system is a substantial utility investment that impacts many of the utilities operations and therefore requires a detailed cost/benefit analysis. The costs of developing and deploying an AMI system are primarily dependent on two key design decisions: (1) the performance characteristics and different applications that utilities, regulators and customers want the new system to support (functional capability); and (2) hardware and other engineering choices for meter integration, communication systems and the network management function(s).

A cost-effective AMI system should minimize the system design and implementation costs and maximize the system's functional capabilities. To achieve this requires considering the tradeoffs between different system design options and various capabilities. It is also almost certain that an AMI system design that attempts to provide all the possible applications/functions to all customers all of the time will not be cost effective. However, the system design should not compromise the capability to support either the dynamic tariffs or operating flexibility that the Commission has directed respondent utilities to consider in their AMI business case analysis. Targeting the middle ground will require both engineering and economic choices. We expect utilities to consider these cost tradeoffs and identify functions that may sound good on paper but are unlikely to provide the level of benefit to justify the investment cost in the long run.

The following examples illustrate some of these design tradeoffs that need to be considered:

1. <u>Interval Data Collection Requirements</u> – Interval data can be used to support three basic functions: (1) provide the billing metrics to support a particular tariff or rate, (2) provide

[3] The functional subcommittee consisted of representatives from PG&E, SCE, SDG&E, TURN, CUE, DCSI, eMeter, Itron, Silver Springs Network, and Auriga Corporation.

information to support utility operating applications like forecasting or outage management, and (3) provide information to support customer education or bill dispute resolution. Utilities should evaluate both the data granularity (e.g. 5 minute, 15 minute or hourly time boundary) and frequency (e.g. daily, monthly, etc.) of data collection needed to support the targeted applications. In this evaluation utilities should consider the cost trade-offs of having different data collection requirements for different types of customers and how this approach reduces system communication, data management and network costs. For example, it is unlikely that small residential customers will have the same information needs as larger commercial and industrial customers. Furthermore, defining a minimum default metering and data collection requirement for a class or subset of customers should not exclude this system option, in case customers choose to pay for additional information retrieval capability.

2. Billing and Other Related Applications – To realize the full AMI system potential, internal utility billing and other applications will need to be modified to make use of AMI capabilities. How these changes are managed can also result in dramatically different system costs and capabilities. For example, how do you determine whether it is economically feasible to modify an internal billing system (either a legacy system or a recent upgrade), when both the new dynamic rates to be supported and the potential number of customers who will opt in or opt out into these new rates is uncertain? Modifying an internal system requires a substantial up-front investment, time commitment, and a level of change generally capable of supporting the worst case cost scenario – full, rapid deployment for the maximum numbers of customers. While it may be more economical to scale the investment to meet the need for new billing capability as it occurs, this is usually not possible with just changes to internal system. However, outsourcing the ability to bill customers for new or special rates under contracts that can be scaled to actual implementation levels provides potential option to reduce costs and accelerate implementation. We expect respondent utilities to document these types of tradeoffs that were considered in the business case, including identification of any regulatory/legal barriers to modifying internal systems or outsourcing the work.

3. Deployment and Staging of Applications and Systems – the cost effectiveness of implementation are determined by how meter installation and application development are staged. Staff does not believe that it is reasonable to assume that all meter sites have the same value, as well as all internal utility and customer applications. Priorities should be established to guide both the investment and implementation in the most cost effective way. Some applications may need to be developed and implemented immediately, while others may change as needed or be deferred to later stages of implementation. Establishing these priorities is a critical element of the AMI business case and should be considered in the analysis.

Review of Parties' Positions on Functional Requirements for the AMI Analysis

This section identifies the areas of agreement and disagreement by parties on the functional requirements. We recommend that the respondent utilities review a range of system design choices, select their system design choices based on their review, and provide the rationale that supports those choices.

The CPUC provided a broad range of applications that needed to be supported by the AMI system in its initial phase 2 scoping memo and provided more details in its February 19, 2004 Ruling. Broadly speaking, the AMI system needed to provide the metering and communication capability to support a wide variety of economically justified rate and associated customer service options. Further, the ideal AMI system should maximize the amount of demand response that can be achieved cost effectively. The Commission also stated that the specific mix of rates, programs and customer service functions that will eventually satisfy this cost effective ideal is not known a priori. Consequently, the AMI system should be designed with sufficient functional flexibility to anticipate and support a wide variety of potential rate structures and customer service options that the Commission may approve over the useful life of the AMI system.

The functional subcommittee[4] produced a detailed set of tables describing key features of the metering, communication, utility data processing and network management systems which agency staff recommends the utilities should consider in their AMI system design and cost benefit analysis (these tables are attached as Appendix A.) Agency Staff supports most of the functional specifications proposed by the sub committee, but we have added more detailed based on the information and input obtained from subsequent workshop(s).

1) Metering and Communication Specification Issues

a. Resolution of Interval Data collection

The subcommittee agreed on the use of 15 minute data collection intervals for all customers above 200kW, but no agreement was reached on the appropriate time interval for small commercial/ industrial (20kW to 200kW) and residential customers. The subcommittee's report correctly points out that the decision on the interval length for smaller customers is driven by the rate design requirements, in meter versus off site data storage, future demand response programs, and other operational needs. In addition, the subcommittee points out that the expectation that there will be different rate offerings for different customer classes has implications on the required level of interval data collection and applications that need to be supported. The utilities have suggested that they plan to recommend a 1 hour time interval for residential customers, but disagreed on whether 15 minute or 1 hour intervals are appropriate for small commercial customer.

Recommendation – Staff agrees and recommends using a 15 minute data collection interval for all commercial and industrial customers >200kW for the system design and cost benefit analysis. However, staff recommends directing the utilities to provide an analysis of the incremental costs of extending the same time interval down to all small commercial and industrial customers (C&I customers with monthly

[4] The functional subcommittee consisted of the representatives from PG&E, SCE, SDG&E, TURN, CUE, DCSI, eMeter, Itron, Siver Springs Network, Auriga Corporation.

average loads greater than 20kW and less than 200kW) as opposed to using 1 hour time intervals. Based on this analysis, the utilities should then recommend the most appropriate/cost-effective time interval and should also discuss to what extent the system they have specified has the capability to remotely redefine this time boundary if a shorter time interval is required in the future.

b. Communication Link to the Customer (Notification for CPP rates)

The Commission's February 19th Ruling specified analyzing an AMI system that would support six basic functions, which included two functions related to the type of communications links that should exist to allow customers to access their energy usage data. These six functions are listed below with the two relevant functions highlighted in italics.

1. Implementation of the following types of price responsive tariffs:
   a. time of use
   b. critical peak pricing with fixed day ahead pricing
   c. critical peak pricing with variable or hourly notification
   d. two part hourly Real Time Pricing
2. *Collection of usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.*
3. *Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference for frequency of access do not result in additional AMI system hardware costs in the future.*
4. Compatible with applications that utilize collected meter data to provide customer education and energy management information, customized billing and complaint resolution
5. Compatible with utility System applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading outage management, reduction of theft and diversion, improved forecasting, etc.
6. Capable of interfacing with load control communication technology.

There are two separate communication functions that potentially impact the AMI functional requirements above: (1) links that allow the customer to obtain access to their interval metered and related data and (2) links that provide the customer with notification or other information regarding a rate or other utility application. These links can be integrated into a single meter system specification or addressed independently.

The subcommittee discussed the information criteria (numbers 2 and 3 above) but could not reach agreement on how to translate these into system requirements or customer needs into functional specifications. The group could not reach agreement on the frequency that some or all customers need to access their electricity usage data via a communication link to their own meter data, or whether additional technology needed to be provided on the customer's end of the system, to allow real time access to their energy usage data. This is understandable given that there is a wide variety of opinions related to what fraction of customer in different customer classes will want to access this information on a real time basis: within 15 minutes to hourly intervals, daily, or even on a monthly basis outside of their receipt of a monthly bill.

The communication link necessary to support dynamic rates and other utility applications was raised again at the WG 3 scenario development workshop on March 29, 2004. Consistent with the Statewide Pricing Pilot design constraints, respondent utilities anticipated using mass media to provide customers with day-ahead notification of a critical peak pricing periods. However, WG 3 members suggested that this medium may not be sufficient for following reasons:

- CPP and other tariff designs that require day-ahead or several hours advance notice cannot also address system emergency, ancillary service and other dispatchable reliability needs that potentially provide the system with substantial value. Designing CPP and other tariff options with similar notification features like those in conventional air condition load control programs do not require advance notice and need to be fully considered.
- Customers with automated control technologies triggered by CPP price signals could be provided with different notification options than those without such technology. Simple plug-in notification devices may also be considered for those with and without automated control equipment to enhance CPP system value.
- Even an extremely well designed mass media strategy to notify customers would not reach a significant fraction of customers on CPP rates, and could prompt some customer complaints, or refusal to pay the higher CPP rates.
- There may also be legal requirements that require utilities to notify each customer when the rate is dispatched by phone, email or some other medium where a clear record of notification can be obtained.

WG 3 members requested additional clarification on the type of communication system necessary to support this "notification" function. The current notification system used in the statewide pricing pilot allows for customers to choose either phone or email as their preferred notification medium for CPP events for a small number of customers, 1200. However, this type of notification system may not be cost effective/feasible if implemented statewide.

Recommendations to resolve the issue:

The subcommittee's recommendations for resolving these issues can be found in the final column of section 1a of their system component tables (see appendix A, page A-3.) Basically the recommendation is to allow utilities to investigate the cost and value tradeoffs of different types of communication links (assuming different levels of customer interest in the meter data and frequency of retrieval) for different classes of customers and present those options to the Commission as part of the business cases analysis. Staff concurs with this approach but notes this does not resolve the "notification" issue described above.

Staff believes that any AMI system used to support critical peak pricing tariff with a day ahead notification must have a more direct and affirmative customer communication plan than simply publishing a notice in a newspaper or making a public service announcement via radio or television. At a minimum, respondent utilities should research the legal issues identified above and present the incremental costs and feasibility of at least three other notification systems:

- E-mail notification
- Phone notification
- On site notification - using plug-in type devices.

On site notification could happen via signals sent to the meter which in turn can communicate with either an LED display in the home or some other video appliance such as a TV monitor or PC screen. The transmitter could also notify the customer directly using a wireless network outside of the metering system. Utilities should explore both options.

The purpose of this more comprehensive notification system is to ensure that all customers at least have the opportunity to retrieve a notice of CPP dispatch, in the event they do not receive the alert/message via radio or TV announcements.

After this analysis is complete, respondent utilities can select one of these options and include its cost in the AMI system, or present an analysis that supports their original recommendation to use mass media to notify customers. Staff invites comment on both its characterization of the options and identification of other notification options that may be a better approach.

c. Other Functionality Issues that were raised at the Scenario Development Workshop

At the March 29th workshop, a discussion was held by the WG3 group on the idea of using the AMI system to send a signal simultaneously to hundreds or perhaps even 1000's of customers' programmable thermostats or load control devices as way of curtailing load during system emergencies. This system set-up could theoretically provide a far more effective and less disruptive response to system emergencies by immediately reducing power usage by 10 to 20 percent for large numbers of customers with automated load control equipment, instead of blacking out or reducing usage by 100 percent for whole neighborhoods of customers via rolling blackouts.

Vendors in the audience noted that this capability was not part of the subcommittee's initial specification report or the Commission's functional list. WG3 members asked for guidance on whether or not the costs and benefits of including this additional functionality should be included in the AMI analysis.

Staff recommends directing the respondent utilities to research and develop system and facility level costs of adding this additional functionality and to weigh these incremental costs against the potential benefits of reducing the need and/or probability of calling rolling blackouts during system emergencies. The utility should then report its estimate of the costs and benefits of adding this reliability capability as part of the Demand Response + Reliability case.

Staff also recommends directing the utilities to investigate the possibility of replacing the current 100 percent electricity curtailment during system emergencies (rolling blackouts for some customers) with a system that requires partial curtailment (5 to 20 percent load drops) for some customers as a condition of service (with or without rate discounts). This system can be designed to produce emergency load drops in those areas with system constraints.

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Section 4 - Proposed Analysis Framework for the Advanced Metering Infrastructure

This section reviews the Commission's cost/benefit policy guidance, proposals from respondent utilities, and input from WG 3 members from the workshops on the costs and benefits that should be included in the AMI analysis framework. Based on this review, agency staff recommends the analysis framework and format presented in this section for the submission of benefit and cost analysis later this year. The analysis relies on the initial policy guidance from the Commission February 19th Ruling, the subcommittee report[5] recommendations on specific categories of costs and benefits for inclusion in the AMI analysis, and the March 29th and 30th workshop discussions on the parameters that could be used in the development of specific AMI rollout scenarios.

This section is organized as follows:

1. Description of the Scenarios to be Analyzed in the Business Case Analysis
2. Common Categories of Costs to be Included in the Analysis
3. Common Categories of Benefits to be Included in the Analysis
4. Staging of Benefit Cost Analysis
5. Common Analysis Parameters for each of these Cases
6. Rate Choices to be Offered in the Demand Response and Demand Response + Reliability Case
7. Methods for Estimating the Level of Demand Response
8. Methods and Parameters for Valuing Demand Response-
9. Methods for Dealing with Uncertainty

Section 4.1 - Description of the Scenarios to be Analyzed in the Business Case Analysis

Consistent with previous Commission guidance from the February 19th ruling, respondent utilities are expected to estimate the capital and maintenance costs of the metering, billing, and communication systems infrastructure for three scenarios:

- Business as Usual
- Full Scale Rollout
- Partial Scale Rollouts

An overview of the costs and benefits that should be included in each case is presented below.

1. Business as Usual Case – This case should include the expected capital and maintenance costs associated with maintaining the current metering and communication systems for all customer classes. This analysis should include any currently planned upgrades to the

[5] This report was drafted by a subcommittee of WG 3 members including David Hungerford, CEC,Tim Vahlstrom, PG&E, Jana Corey, PG&E, Paul Kasick, SCE (by phone), Doug Kim, SCE, Jeff Nahigian, TURN, Tanya Guleserian, CUE, Ward Camp, DCSI, Chris King, CCEA, and JC Martin, SDG&E .

metering and billing systems for the period 2006 to 2021. If possible these costs should be estimated on an annualized basis for the analysis period.

2. Full Scale Rollout of an Advanced Metering Infrastructure – This scenario should estimate the costs and benefits of designing and implementing an advanced metering infrastructure that serves all existing customers. This case should include a description of how the utility plans to phase the meter installation and a description of the criteria used in deciding the fraction of customers that can NOT be reached economically by the new communication system. This system should support the applications and functional requirements discussed in Section 3.

    a. Costs - This analysis should include the expected start up and capital costs of designing, purchasing, and deploying the advanced metering infrastructure and the annual expected costs of maintaining and operating this system from 2006 through 2021. The analysis should clearly specify the costs anticipated at each stage of the deployment cycle-- system design and testing, beta testing of the interface between billing and metering systems, and any other milestones between rollout and the completion of meter installations and integration into the network

    b. Benefits - This analysis should include an estimate of the present value of the potential benefits identified in the benefit cost section below over the same analysis period specified above. Respondents should also provide a qualitative discussion of the AMI system benefits if there is too much uncertainty in the dollar value estimate. Benefits should all be calculated relative to the baseline conditions expected in the business as usual case.

3. Partial Rollout Scenario – This analysis should include a description of the rollout options being considered by the utility in its design process and the rationale for choosing its preferred case. Utilities need to explicitly specify the criteria used to design the partial roll out case. Examples of such criteria discussed at the March 29, 2004 WG3 scenario workshop included: identification of contiguous neighborhoods with relatively high "meter density" and identifying zones or areas with relatively high potential for price responsive demand.

    During the scenario workshops, PG&E suggested that some criteria be ruled out for inclusion in the construction of partial roll out case which includes: Opt in choice for dynamic rates, targeting installation of advanced meters in new construction only and high usage only customers within customer class. While staff understands the rationale for these suggestions, we see no reason for excluding these cases without an analysis. Parties need to demonstrate through analysis that one or more of these options is not feasible, practical, or cost effective.

    Costs - This case should include the same startup and capital costs described in the previous cases and should explicitly identify the costs of the billing system(s) needed to bill customers with the new meters and those customers that remain on the old meter system.

Benefits - This section should include annualized estimates of the benefits expected to accrue during the rollout to both the customers who receive the new meters and any system wide benefits such as reduced procurement costs that will be spread to all customers. This discussion should explicitly specify whether or not some of the expected operational benefits from a full scale roll out of an AMI system (reduced meter reading costs) can be captured through a partial roll out. The analysis should also specify whether the cost reductions are higher or lower than the expected increase in costs from the need to run parallel billing systems for the different meter networks.

Section 4.2. - Common Categories of Costs to be Included in the Analysis

Background

The WG3 formed a cost/benefit subcommittee to develop common set of cost and benefit categories for consideration and inclusion in the AMI analysis framework. The subcommittee did an excellent job of coming up with descriptions of common cost and benefit categories (subcommittee report is attached as Appendix C). During our review of the subcommittee's report staff identified some technical terms and issues of balance that need to be addressed before the analysis can begin. Below we reprint the subcommittee's recommendations by cost category and offer comments and recommendations for change if needed.

Overview of Cost and Benefit Categories for AMI Analysis

The subcommittee identified 93 categories of cost and 39 categories of benefits (full list is in Appendix C.) These categories are grouped by major system category listed below:

- Meter installation and maintenance
- Communication infrastructure
- Information technology and applications
- Customer service systems and
- Management and miscellaneous costs

The sub-categories within each of the categories above are listed in no specific order and in some cases it is not possible to discern if the costs are part of a design process, installation costs or regular operating costs.

Recommendation – Staff recommends that the actual cost estimates be grouped into the following cost categories in the AMI benefit cost analysis:

1. Start-up costs (design, contracting, training, hiring temporary installation crews, etc.)
2. Installation costs (purchase and installation of advanced meters, installation and testing at customer premise, new software, communications networks, etc.)
3. Maintenance and operating costs (cost of reading meters, translating data to bills, sending bills out and managing the network, etc.)

The subcommittee's report also contains a description of the methods that will be used to estimate costs and benefits, which includes the use of five separate methods for estimating costs: Request for Proposals (RFP's), benchmarks from other utilities, indirect benchmarks, in house analysis and actual costs to estimate some or all of the costs associated with AMI deployment.

Recommendation – Staff supports the subcommittee's proposed methodologies for the benefit and cost estimation and recommends adopting them for the AMI analysis.

A. Review of Meter Cost Categories

The subcommittee report (Appendix B) includes fourteen proposed categories to for costs associated with meter design, installation, testing, maintenance, and meter disposal. Staff supports the use of these common set of cost categories for inclusion and estimating costs for the three business case scenarios: business as usual, full scale and partial roll outs. The only exception is the final three cost categories in the subcommittee list: additional O&M meter costs, higher meter replacement costs (lifecycle) and the cost of pick up reads. These are incremental costs that are appropriate for reporting in the full scale and partial roll out but not the business as usual case.

B. Review of Communication System Costs

The subcommittee's report identifies 17 categories of costs to include in the business case. However the language used in the report is highly technical, so Staff has reworded portions of the report to help clarify and understand the this technical language.

<u>B.1 – Design Costs of the Communication System</u>

Line C-1 Committee Draft: C-1 Establishing backhaul strategies and contracts (including contracts with public networks)

Line C-1 Staff Edit: Review and develop strategies to retrieve information and process the information with the central billing system

Line C-2 Committee Draft: Physical and logical security, securing data transmission, infrastructure to support security, etc.

Line C-2 Staff Edit: Costs to <u>review and specify systems to ensure</u> physical and logical security of data, securing data transmission, infrastructure to support security, etc.

Line C-4 Committee Draft: Site surveys to determine placement of network equipment

Line C-4 Staff Edit: <u>Perform</u> and review site surveys to determine placement of network equipment

B.2 – Communication System Operation and Maintenance Costs

Line C-5 Committee Draft: Costs of backhaul contracts and services

Line C-5 Staff Edit: Ongoing costs of data retrieval contracts and services

B.3 – Missing Communication Cost Categories for Business as Usual Case

The committee report does not include communication costs associated with the current metering and billing system. Staff believes there are existing costs of communicating information from current meters that include the costs of meter readers, downloading information from them to the central billing system and then communicating this information to the billing processing centers for bill production. In addition there are costs associated with keeping this information safe and secure. Staff recommends quantification and inclusion of all of these ongoing costs to allow for a valid comparison of the communication system costs between the two AMI scenario cases and the base case scenario.

C. Review of Information Technology and Application Costs

The subcommittee report developed 17 separate categories of costs for developing and deploying new software and hardware capable of supporting the new AMI systems. However, the categories are not currently linked into design, purchase, testing or ongoing costs.

Recommendation – These 17 categories of information technology costs need to be separated into design, purchase, testing, and deployment costs for the cost benefit filing.

The list of cost categories seems complete but may not capture a series of difficult tradeoffs utilities may need to make when deciding to replace or modify their existing computer information system(s) to handle the greater volume of data from the advanced meters.

Recommendations:

1. Utilities need to specify the key factors associated with their decisions to upgrade existing CIS systems, completely replace them, or outsource the entire process of delivering electronic reads for billing customers. If possible the costs of alternative options for billing/data management should be specified.
2. Cost estimates to support the current information technology system used for processing meter reads and converting them into bills for each cost category should also be specified for the business as usual case to ensure a comparable comparison.

D. Review of Customer Service Costs

The subcommittee's report identifies 9 customer service cost categories. The first three categories reprinted below refer to costs associated with rolling out new rates. Staff recommends excluding these costs from the business case, consistent with the Commission's directive. The operations case should focus on estimating the operational benefits of the new system and comparing these to the costs of installing an AMI system without assuming the deployment of dynamic rates. These costs and benefits should be dealt with when the utilities develop and deploy the new dynamic rates.

The following customer service cost categories should be excluded from the operations cost benefit analysis:

- Customer education on rate changes / customer communications campaign
- Out-bound communications (mass media costs, e.g., print, radio, TV) for CPP or other rate notifications
- Additional rate analysis due to multiple TOU options

E. Review of Management and Other Costs Categories

The subcommittee report includes 18 categories of miscellaneous costs ranging from project management costs to customer acquisition costs to the costs of shifting costs from C&I customers to different ratepayers. Some of the cost categories appear to overlap and describe similar costs that should be separated. For example line M-2 Buyout of Current Itron contract for 2000 ERT deployment seems similar to the category M-4 Costs of Stranding existing utility systems and line M-3 Cost impacts of early removal of assets (existing meter inventory-stranded investment).

Other categories of costs are not clear; for example: Capital financing costs, customer acquisition and marketing costs. Other cost categories are difficult to separate from normal business operations such as the cost of employee communications and purchase of change management or "work management tools".

Recommendation – Utilities should provide a more detailed description of the following common cost categories in this management area.

Line M-2 - A description needs to be provided on the original cost of the Itron contract for ERT deployment and the business case that was used to support this investment. Please include the Commission decision that authorized the collection of revenues for this investment.

Line M-3 - Impacts of early removal of assets – Specify the method that was used to estimate these cost impacts and the details of the calculation related to useful life of the assets.

Line M-5 - Risk contingencies (technological obsolescence/reliability). Technological obsolescence is a risk that is incurred for all new investments as well as the decision to stay with the current metering system. If these contingencies are to be quantified, the analysis should be symmetric and identify the risks of not upgrading the current system in addition to quantifying the costs of purchasing a new AMI system. Were these risks of technical obsolescence ever estimated in previous rate or business cases?

Line M-9 - Work Management Tools – Specify what types of tools (software, hardware) are being considered and how they are different from the management tools in current use.

Line M-15 - Capital Financing Costs – Specify the types of capital costs included in this line item. Please ensure these costs are not also included in the price quotes for the metering, communication and billing systems.

Section 4.3 - Review of Benefit Categories to be Included in the AMI analysis

The subcommittee report identifies four major categories of benefits:

- System Operations Benefits
- Customer Service Benefits
- Demand Response Benefits
- Management and Other Benefits

Each benefit category is discussed below:

<u>Systems Operation Benefits</u>

The subcommittee report suggests that six of the twelve types of benefits in the system benefits category cannot be fully quantified. The primary reason for this is the fact that system engineers have not yet experienced the benefits of many of the additional functional benefits of AMI systems, which can range from the ability to better manage outages to providing for remote service connects and disconnects. Staff concurs with this assessment that these benefits cannot yet be quantified, but recommends that respondents contact other utility staff with AMI systems to collect benchmark data, and/or qualitative assessments of the level of benefits.

<u>Customer Service Benefits</u>

Similarly the report suggests that only 3 of the 13 potential benefits categories can be quantified, primarily those that improve the accuracy of the metering and billing process. Other benefits listed include improved value to customers of more frequent and better information about their energy usage patterns, more timely and accurate bills, opportunities for lower bills, and opportunities to exercise choices in rate options. Clearly these types of increased customer services will have value for some customers and there is an ample literature that suggests customers appreciate these types of services.

Staff supports the proposed method of discussing and possibly quantifying the benefits in each of these uncertain areas included on page 2 of the Subcommittee report. The subcommittee approach includes an exhaustive review of previous utility experience in categories currently deemed qualitative and attempt to identify benchmarks that can be used in the California context. The six potential methods of quantification range from the use of actual results, to deriving unit based benchmarks, to simply describing utility experiences in each category on a qualitative basis. Staff also suggests that the Commission consider requiring utilities to track and document their actual experience in these hard to quantify categories, if an AMI rollout is pursued.

Demand Response Benefits

The report identifies two categories of demand response benefits that can be quantified, procurement cost reductions and increases in system reliability value in the form of a capacity buffer during peak periods. Staff supports both of these conclusions.

The report also identifies the potential of using the new system to manage dynamic fuel switching and dispatch of distributed generation but concludes these benefits cannot yet be quantified. Staff supports this conclusion.

The report states that the potential benefits of avoided transmission and distribution costs are still considered too uncertain (long term) and not quantifiable. Some parties at the demand response quantification workshop disagreed with this view and suggested that respondent utilities use the estimates of avoided transmission and distribution costs developed by Energy and Environmental Analysis (E3 report) for the Energy Division. Some parties felt the benefits could be counted on if the dispatch of demand response rates were tied in with local dispatch and management decisions.

Recommendation – Utilities should provide their estimate of the value of avoided transmission and distribution costs for a given level of demand response using the estimated values from the E3 report or their own forecast of avoided transmission and distribution costs. After reporting this value, respondents should make their own judgment based on the probability that these benefits will be realized and discount these benefits accordingly. The rationale for this assessment should also be provided in work papers.

Management and Other Benefits

The report identifies five benefit categories that can be quantified in the short run related to the miscellaneous operation benefits and three other benefits related to tariff planning, reduced need to carry large meter inventories, and the use of GPS systems to improve matching of customers to local governments.

Recommendation – Staff supports the benefit categories and approach recommended by the sub committee.

Section 4.4 - Staging of Benefit Cost Analysis

Staff recommends the following process and parameters be used to group the benefit cost categories identified in the previous sections, on a uniform basis across utilities. These recommendations are based on the discussions at the workshops and the need for a common reference point for the Commission to use in comparing analyses across utilities.

First three cases should be analyzed for the full and partial roll out scenarios:

A. Operational Case – Utilities should first provide their estimates of the costs and operational benefits associated with the following categories:

   Costs: Metering costs, communication costs, information technology and management costs. These costs represent the utilities cost of implementing an AMI system absent a decision to incur additional costs or benefits from developing and deploying new demand response rates or programs. This should be labeled the core operations case (note: this case does not include the cost categories related to additional customer service costs included in the subcommittee report.)

   Benefits: Systems operations benefits (include rows c1, c2, c5, c7, c10 and c11, rows from the spreadsheet), the customer service benefits section (include rows 1, 2, and 4), and management benefits (include rows 1, 2, 3, 5, and 6.) These categories include benefits that are expected to occur whether or not new dynamic rates are deployed to some or all customers.

B. Demand Response Case – This analysis should include the costs and benefits of rolling out a given set of dynamic rates (discussed below under rate design parameters.) This analysis should include all of the cost categories from above and the additional costs and benefits of deploying the rates from both the utilities perspective as well as from a societal perspective.

C. Demand Response Plus Increased Reliability Case– This case should include all of the benefits and costs of Demand Response Case, but add the estimated costs and benefits of using the AMI system to send out emergency signals to reduce the load of all customers signed up for dynamic rates by 10 to 20 percent. This estimate should include the costs of any control system deemed necessary by the utility and the estimated fraction of customers signed-up for this “mandatory” load control rate under two different assumptions:

   1. Customer must voluntarily agree that their load could be curtailed for 30 minutes to an hour in return for some form of payment related to the value the utility system received by this emergency response capability.
   2. The Commission decides that having this emergency curtailment capability as a condition of service for all new customers.

   The benefits of having additional reliability capability should be estimated by

      a) Estimating the probability of having a stage 2 or 3 emergency during the analysis period;

b) Estimating the impact of using the new AMI network to deliver a partial load reduction signal equivalent to reducing the load by 20 percent for 20 percent of the customers within an hour of the signal on this probability;
c) Valuing this reduction in the probability of blackouts using the most recent value of service studies for each customer class.

Section 4.5 - Common Analysis Parameters for each of these Cases.

The following analysis parameters should be used consistently across each of these cases:

1. Duration of business case analysis periods – 2006 to 2021;
2. Discount rate equal to the utility cost of capital;
3. A 5-year roll out period for deploying advanced meters to over 90 percent of customers in full scale case roll out;
4. All costs and benefits should be presented in annualized values in work sheets and then converted to present value in 2004 dollars;
5. Weather conditions – Utilities should estimate the level and value of demand savings using both typical weather conditions and at least one hot summer with weather conditions approximating a 1 in 10 summer. The final estimate should include some probability and weighted sum of these two weather conditions.

There are a number of other physical design parameters that were discussed at the scenario development workshop and general agreement was reached to not specify a universal or common set of assumption across all utilities or cases for the following design parameters:

- Fraction of customers to receive advanced meters (range is between 85 and 95 percent for full roll out);
- Time interval of data resolution in meter;
- Amount of storage capability in each meter;
- Frequency of polling data from meter;
- Communication medium used to poll data;
- Method and cost of providing customers with access to their own energy data;
- Fraction of customers likely to use this option: as part of system and if billed as a separate customer charge;
- Proposed sequencing of gas meter installations for dual fuel utilities installing meters for both electric and gas reads;
- Method of notifying customers if a critical peak price is dispatched;

For these parameters respondents should both identify the preferred final parameter choice and the reasons for their selection.

Section 4.6 - Default and Opt out Rate Choices to be Offered to Customers

WG 3 discussed the possibility of offering customers a number of different rate types as well as switching customers to a new default tariff on an opt out basis. For the purposes of comparative analysis, staff recommends that the utilities analyze the impacts of the following rate structures and roll out strategies:

1. Change the default rate for all customer classes to a two period time of use rate by 2008 with the option to switch to CPP-F rates or their currently applicable tariff;
2. Change the default rate for all residential customers to CPP-F with the option to switch back to time of use or inverted tier rates; CPP-V for small commercial and industrial classes (with the options to switch back to the current tariffs) and two part real time tariffs for large commercial and industrial customers (with demand greater than 200 kW) with option to revert back to existing time of use tariffs.
3. Maintain the current underlying rate tariff for all customers but require that utilities develop a new optional rate structure that reduces costs for all off peak hours to compensate for the possibility that customers will be exposed to pure CPP emergency tariffs for up to 4 hours per day for 15 days per year. This structure would be available on an opt-in basis.
4. Maintain the current rate structure and offer CPP- F or V rates to all customers on a voluntary or opt in basis.

Rationale – Staff believes that it is important to analyze the potential costs and benefits of switching the default rate for all customers to time varying rates. Society is likely to benefit from more efficient use of generating resources, if the majority of customers receive price signals that reflect the marginal costs of supplying electricity. One way of achieving this outcome is by changing the default rate structure to either time of use or critical peak pricing rates and then allow customers who prefer the certainty and perhaps extra cost of a fixed flat rate or inverted tier rate to make that choice.

Section 4.7 - Methods to Estimate Demand Response

Estimated load impacts from the deployment of the AMI infrastructure and associated rates are a function of the assumed level of participation in each rate option offered, the assumed price elasticity, and the assumed on peak to off peak priced differential. Most parties suggested, at the March 30, 2004 demand response quantification workshop, that they plan to use elasticities derived from the statewide pricing pilot to estimate the level of demand response per customer for residential and small commercial customers. Elasticity estimate for medium and large customers were not discussed at the workshop but could be derived using elasticity estimates from other utility areas. WG 3 members had no opinion yet on the appropriate default rate by customer class or projected customer shares by rate types but a range of plausible choices for point elasticity values was presented at the workshop by CRA. Staff's recommendation on elasticity and customer opt out rates are provided below.

Recommendation – Staff notes that the uncertainties associated with point estimates available for class level elasticities from the CRA report are still high and as such it is probably not appropriate for the Commission to adopt a common elasticity value for one or more classes now. One case that should be examined is the final elasticity results estimates for each customer class and climate zone as reported by CRA in their final SPP report (mike-this would only include elasticity estimates for res and small C&I customers). In addition, we recommend the Commission allow each respondent utility to use their own point elasticities. The uncertainly around this estimate should explored by using Monte Carlo simulations to simulate the range of possible outcomes around this point estimate. We support the methods proposed to capture this uncertainty by CRA at the March 30th workshop.

Opt out Fraction – CCEA presented a review of opt in and opt out rates from previous dynamic rates and demand response programs for small customers. CCEA found that the opt-out rate varied from 5 to 20 percent for residential customers. CCEA's analysis used both opt out rates from current tariffs as well as the opt in rates for time of use tariffs. The range of opt out fraction identified in an analysis from Momentum Inc for residential customers ranged from 8 to 33 percent at an assumed awareness rate of 100 percent. WG3 members requested that the Commission set a common or base opt out rate for the purposes of comparison.

Recommendation – Staff recommends the use of an opt out rate of 20 percent for the common reference case. This means that analysts should assume that 80 percent of the customers will choose to remain on their assigned default rate. Again respondents can identify the opt out fraction they support and use this in their preferred analysis, but should run at least one consistent scenario using this assumption for the full scale roll out.

Section 4.8 - Methods to Value Demand Response

WG 3 members identified three valuation methods for valuing the level of demand response expected in response to the deployment of dynamic rates under a full or partial roll out scenario. The first method relies on production cost simulations and analysis to produce avoided energy cost estimates by utility area and by year for 8760 hours per year over the next twenty years. A summary of a forecast derived by using this method was presented by Energy and Environmental Economics. The second method relies on the use of a point estimate of the marginal cost of capacity, marginal cost of on peak energy and marginal cost of off peak energy to be used for the entire 15 years of the analysis period. The advantages of this method is its simplicity and reliance on known costs of producing power during peak periods today. Its disadvantage is that it does not analyze how today's costs might change over the next 15 years. The third method proposed by SCE for consideration would be to conduct a full scale resource planning analysis and treat the introduction of dynamic rates to specific customer classes in a similar manner to the introduction of a new peaking plant. This method would rely on numerous runs of production cost models to simulate the value of demand response based on the specific resource mix and plan of each of the respondent utilities.

Recommendation – Staff believes all of these approaches potentially have value and would not presume to recommend a "best" method. However for the purposes of comparing between utility analyses, the Commission should consider adopting a simple reference case using the following simplified set of assumptions for use in the base year 2006 by all three IOU's:

1. Value capacity at $85/kw-yr (cite to previous CPUC order (or use whatever value is ultimately adopted in the market price referent analysis);
2. Value off peak energy at 4.5 cents/kWh and energy used during the peak period at 15 cents/kWh.

Of course each utility can present its preferred approach to valuation and resulting estimates of value in addition to presenting the results of this case.

Section 4.9 - Methods for Dealing with Uncertainty

The cost and benefit estimates used in this analysis are by definition forecasts of future values that are uncertain. One way of reacting to this uncertainty is to simply decline to estimate a value and report that the value is so uncertain that it is not possible to estimate. This appears to be the case in many categories of benefits that are likely to be provided to customers by AMI systems but are listed as uncertain in the subcommittee report. Another way to deal with uncertainty is to bound the range of uncertainty around the estimate and use statistical techniques to understand how the uncertainty effects the bottom line result. CRA presented one method of dealing with uncertainty through the use of Monte Carlo simulation techniques to identify the probability associated with any particular estimate of costs or benefits. Staff prefers the second method.

Staff recommends the respondent utilities be directed to estimate ranges of uncertainty for each of the key parameters in this analysis and use the Monte Carlo simulation or other statistical techniques to understand how the uncertainty may affect the AMI analysis results. At a minimum this list of key parameters should include:

- Price elasticities
- Rate choice fractions
- Value of demand response at peak- no emergency
- Value of demand response during emergency conditions
- Likely reduction in customer bills
- Overall AMI network costs

Respondent utilities are encouraged to develop a reasonable range of estimates for these values and use them to help understand the uncertainties in estimates of both benefits and costs.

Section 5 - Recommended Schedule to Complete the Business Case Analysis

Staff recommends that the Commission require the respondent utilities to produce a dry run or preliminary estimate of the benefits and costs of various AMI deployment scenarios by October 1st using the elasticity and rate preference results gathered from the SPP to date. We also think it would be a good idea to schedule an optional workshop in the middle of the analysis period perhaps August 5th to allow parties to get together and discuss problems or uncertainties discovered during the course of analysis and determine if any joint actions could mitigate the problems or at least reduce uncertainties. The preliminary analysis should then be updated using the more complete results from the entire summer of 2004 in a filing on December 15, 2004.

Appendix A
Subcommittee Recommendations on Functional Specification Issues

System Component	Description / Discussion	Issues Requiring Clarification
1. Meters	Meter systems generally include a variety of sensing, recording, processing and communication capability. At a minimum, the meter system must provide capability to sense and record various electric operations and then communicate information back to the utility. Basic functional capabilities should include capability to: x collect and store interval data (see issues) x provide processing at the meter or within the system, where necessary, to support essential customer service and system operating applications. x provide optional capability to support customers with direct or other real-time access to meter data x provide capability to remotely access (download or otherwise communicate) meter data to support customer billing, system operation and customer service and educational applications	The resolution of interval data collected is usually determined by the specific rate, information or system application to be supported. While the ACR specifies different potential combinations of rates targeted to three distinct classifications of customers, Appendix A specifies that interval data will be collected at a minimum of 15-minute intervals. The resolution of interval data collected will affect AMI system specifications and cost. The utilities recommend a clarification of interval data recording to differentiate between the customer classifications. There is consensus on the largest C/I and smallest Residential customers, however there is a lack of consensus regarding the breakpoint C/I customer in the middle. See 1b for Subgroup recommendation. <u>Recommendation by the Function Subgroup</u> Meter system functional specifications assume compliance with all net metering, safety, data accuracy and other legal requirements not directly addressed by the ACR.
1a. Communication Link to the Customer	Meter systems may also include capability to (a) allow customers to use supplementary equipment to connect to and access real-time information directly from the meter (hard wired KYZ port) (b) communicate information wirelessly in real-time from the meter directly into the customer facility, or At a minimum, the AMI system should provide capability to communicate information to the customer through other hardwire, wireless, internet,	There is consensus that all customers may need or can use access to their energy usage information. However, there is no consensus regarding either the customer need for or technology necessary to support real-time access to meter data. There is consensus on two points: (1) a real-time link would raise the cost of the meter and (2) the largest C/I customers have a more established need for this type of information than small C/I or residential. <u>Recommendation by the Function Subgroup</u>

System Component	Description / Discussion	Issues Requiring Clarification
	paper or other means in less than real-time. Direct, real-time access to meter data may be useful in supporting energy management, energy monitoring or other customer display applications. This is particularly true for the largest C/I customers. Any communication from the meter directly into the customer facility should be governed by non-proprietary, open-protocol communication standards. Access to less than real-time meter data through other means may be particularly useful to all types of customers to support educational, facility management and other functions.	x Require hard-wire or wireless options for accessing real-time data from the meter for the largest C/I customers (1) For >200 kW under AB1X29, real time is defined as a hard wire option through a KYZ port at the meter or through a utility provided Internet link that provides a minimum 24 hour turnaround. (2) For <200 kW, utilities should identify options that are at a minimum compatible with the same interval recording detail listed in the recommendation under 1b. bullet #2. x Communication from the meter directly into the customer facility should be governed by non-proprietary, open-protocol communication standards. x Allow utilities to specify or make available real-time access to other customers either with economic justification or as a customer charge option. x Require utilities provide customers with several different options to gain access to less than real-time meter data.
1b. Processing and Recording	What is processed and stored at the meter, in local nodes or concentrators that aggregate multiple meters, or in the utility data processing system is determined by the overall system design and basic tradeoffs between the cost of communication and cost and value of data collection and storage. Collecting and processing interval data centrally for all meters on a daily basis, maximizes potential information value by providing immediate access to detailed system operating data and provides great flexibility to quickly change and implement new rate designs. However, there is a tradeoff that must be made between how often and at what level of detail data is collected. Specifically, collecting interval data from all meters daily versus less frequent collection of only the register data necessary to support the customer rate involves a tradeoff in communication, data processing and data storage costs versus application support. The collection, communication and storage of interval data or the same	<u>Recommendation by the Function Subgroup</u>: x Adopt the 15-minute interval data recording level already in place and specified in for the largest C/I customers. x Require the utility AMI meter and system design explicitly address what level of interval data will be established as the default for all other customers below 200 kW. Design requirements should address each of the following: (1) Existing and anticipated rate design/tariff requirements for interval data (2) Existing and potential markets for demand response both at the retail and wholesale level as well as potential aggregation to support ancillary services and other reliability programs, and

System Component	Description / Discussion	Issues Requiring Clarification
	interval recording detail may not be identical or even required for all customers. Rate designs (e.g. RTP, interruptible and demand rates) and system applications (e.g. load survey, outage reporting, etc.) may require different levels of interval data collection and then only from subsets of customers. Meter recording and data transmission capabilities will be driven by three factors – (1) Billing determinants necessary to support the customer rate. a. Centrally processed 15 minute interval data can be collected from each meter and centrally processed to support almost all possible rate designs, however b. Locally processed aggregated meter register data can be used to support most tiered, time-of-use (TOU) and Critical Peak (CPP) rates. To retain flexibility, AMI system designs should provide and/or explicitly address capability to remotely redefine the time boundary or other register collection parameters. (2) Information necessary to support customer billing inquires and system operating and service functions. While customer billing may not require the collection of interval data, selective access to interval data may be necessary to support customer billing inquiries, load survey, system planning, outage management and customer educational applications. (3) Customer information and educational applications - Interval level data in the form of a daily load curve can be instrumental in educating customers regarding how they use energy and what they can do to better manage their energy bill. If interval data is not collected and stored centrally, provision must be made to store data locally sufficient to support anticipated applications and to remotely access this data on demand. See (2).	(3) Utility system operational needs for support of outage management, load survey, customer education and bill inquiry resolution. x Furthermore, utility AMI system designs should be required to provide and/or explicitly address capability to remotely redefine the time boundary or other register collection parameters.
1c. Communication Link to the Utility	Communication capability from the meter to the local node/utility can be supported by a variety of communication methodologies and either integrated or linked system designs. How often data is uploaded from the	No significant issues.

System Component	Description / Discussion	Issues Requiring Clarification
	meter is a dependent upon the system design and the tradeoffs inherent in various system operating and customer service applications. Alarm functions that trigger automatic communication from the meter to the utility may allow less frequent polling and data collection from the remaining meters population.	
2. Communication System	The communication technology choice and system design will be driven by (1) decisions regarding processing and recording, (2) assumptions regarding customer participation and the mix of rates and programs and (3) timing needs of selected system operating and customer service applications. Because of the uncertainties regarding customer participation and the eventual mix of rate designs and program, the actual volume of data transport that needs to be supported is also uncertain.	Recommendation by the Function Subgroup: x Communication systems technologies should be capable of being economically scaled up or down in response to anticipated customer participation levels. x Utilities will be obligated to provide AMI to all customers in all classes, to support as yet undecided rate options. As a result, some minimum level of communication infrastructure must be available 100 percent of the time. Utility business cases should clarify both the design and economic justification for what is proposed.
3. Utility Data Processing	Interval and register data must be validated and edited, at a minimum, in accordance with CPUC billing quality standards. Data must also be integrated into a master customer database to support billing and other utility system functions. As with Communication system requirement, there are uncertainties regarding customer participation, the eventual mix of rate designs and program, and consequent data processing requirements. As a result, data processing systems should be capable of being economically scaled up or down in response to anticipated customer participation levels.	No significant issues.

System Component	Description / Discussion	Issues Requiring Clarification
4. AMI System Network Management	Network management capability must be provided to manage meter data collection schedules, meter and communication system alarms and all other system maintenance and operating functions.	<u>Recommendation by the Function Subgroup</u>: To guarantee open information exchange between legacy, future utility systems and potential third-party customer applications, AMI designs should anticipate and separate information exchange requirements into hierarchical categories to accommodate interoperability.

Appendix B
Quantification Methods for Costs and Benefits

WG3 Benefit-Cost Subgroup
Quantification Methods for Costs and Benefits
Draft February 27, 2004

Summary

The methods listed below will be used by the utilities for quantifying advanced metering infrastructure (AMI) costs and benefits. These methods are listed in order of priority and will be used in this order, unless a method is not applicable or the specific data are not available, in which case the next method in order on the list will be the preferred method. The utilities may use more than one method for a particular item.

Costs

C1. “RFP” – Obtain cost estimates from vendors/suppliers via a Request for Proposal process. This may be for purchase of hardware, software, or services (referred to as “outsourcing” in Appendix A of the Draft Scoping Ruling).

C2. “Benchmark” – Estimate costs utilizing utility resources to perform a specific activity or provide a specific function. Use as inputs into that estimate data from other utilities that have implemented large-scale (over 1 million meters) advanced metering infrastructure (AMI) or, where applicable, automatic meter reading (AMR) projects. Data from other utilities may be obtained directly from those utilities or from vendors or consultants who implemented the projects. AMR-project data would be applicable only for field activities related to meters, such as pickup meter reads, meter installation, panel replacements, and meter operations and maintenance.

C3. “In-house” – Estimate costs utilizing utility resources to perform a specific activity or provide a specific function, but not using inputs from other utilities. This would be the case for existing utility communications or information technology infrastructure where inputs from other utilities are not likely to be relevant. For example, a utility might own a fiber optic communications system for use in communications or have a particular meter asset management software system.

C4. “Indirect Benchmark” – Estimate costs related to indirect implementation costs, such as damage claims, using utility historical records plus data from other utilities that have implemented large scale AMI or AMR projects, adjusted for utility-specific conditions.

C5. “Actual” – Record results following implementation of a pilot or large-scale program, quantify impacts based on results, then multiply by a dollar value for the cost.

Benefits

B1. "Benchmark" – Estimate savings using recorded utility operating costs and anticipated reductions in those operations, utilizing data from other utilities that have implemented large scale AMI or AMR projects and adjusted for utility-specific conditions. Such data may be obtained directly from those utilities or from vendors or consultants who implemented the projects.

B2. "Benchmark, Unit-based" – Estimate benefits by quantifying number of instances of an occurrence or quantifying a level of performance based on historical utility operating data, then multiplying by a dollar value for the benefit. Inputs include utility operating records and data from other utilities that have implemented large scale AMI or AMR projects and adjusted for utility-specific conditions. Such data may be obtained directly from those utilities or from vendors or consultants who implemented the projects.

B3. "Actual" – Record impacts following implementation of a pilot or large-scale program, quantify impacts based on results, extrapolate based on the planned scope of deployment, then multiply by a dollar value for the benefit.

B4. "Substitution" – Estimate benefits by utilizing historical utility accounting data and summing the value of those activities and systems that will be superseded by AMI.

B5. "Qualitative Benchmark" – Some benefits are not quantifiable but will be described qualitatively, utilizing data and information from other utilities that have implemented large scale AMI or AMR projects.

B6. "Qualitative" – Some benefits are not quantifiable but will be described qualitatively, but without using data and information from other utilities that have implemented large scale AMI or AMR projects.

An example of Method B2 is for meter accuracy: the historically monitored meter accuracy level may be compared with the accuracy level anticipated for AMI meters, then multiplied by average revenues per customer (note that in this example the benefits flow to other ratepayers as improved equity, not to the utility).

An example of Method B3 is demand response: record pilot results, estimate overall impacts, and multiply by the dollar value of the benefit.

Method B4 is used to fulfill the requirement of the Joint AC and ALJ Ruling of February 19, 2004, which states: "'the Base Case must identify the actual costs of maintaining the existing metering and related support systems' and 'identify any significant investments in new metering systems made during the last five years.'"

Appendix C
AMI Potential Costs List

AMI Potential Costs List

#	Short Term	Long Term (Quantifiable)	Long Term (Not Yet Quantifiable)	Out-of-Scope	Not Quantifiable (Qualitative Consideration)	
						Meter System and Installation
1	x					Cost of purchasing meters, comm modules and related vendor support equipment & software
2	x					Installation labor (incl workers comp, P&B, payroll taxes, etc.)
3	x					Installation and testing equipment costs (tools, equipment and vehicles)
4	x					Administration of contracts / supervision of installer workforce
5	x					Meter installation tracking systems (Endpoint Link-other), Meter info / records admin / GPS
6	x					Panel reconfiguration / replacement costs (A base, other) / Meter socket repairs
7	x					Potential customer claims related to damages during meter installation and/or panel upgrades
8	x					Additional temporary meter reading staff for transitional period / mtr reader transition costs
9	x					Supply chain management including development of staging facilities, shipment & handling of new meters
10	x					Salvage / Disposal process for removed meters
11	x					Training (meter installers, handlers, shippers)
12	x					Additional costs to O&M / more complex metering & comm infrastructure (labor, tools, equip, vehicles)
13	x					Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)
14	x					Pickup reads (remote retrieval not available / possible)
						Communication System
1	x					Establishing backhaul strategies and contracts (including contracts with public networks)
2	x					Physical and logical security, securing data transmission, infrastructure to support security, etc.
3	x					Costs of backhaul contracts and services
4	x					Site surveys to determine placement of network equipment
5	x					Purchase network communications equipment and hardware
6	x					Development of communications link from meters to data center, LAN / WAN / servers for storage & processing
7	x					Staging facilities for WAN / LAN equip and mounting hardware (pre-installation)
8	x					Training for installation of WAN / LAN equipment (including install labor for wireless circuits)
9	x					Mapping of network equipment on company facilities (asset facility mapping)
10	x					Installation of LAN / WAN equipment (including bucket trucks / crews)
11	x					Dispatching and O&M of field LAN / WAN and infrastructure equipment
12	x					Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)
13	x					Development of Internet based usage data communication
14	x					Auxiliary equipment (e.g. remote antennas, isolation transformers, surge protection devices, etc).
15	x					Cross arms (e.g. streetlight arms for pole top installations) and other mounting
16	x					Pole replacement - to "fit" concentrators
17	x					Electric power consumed by LAN / WAN equipment and/or meter modules
						Information Technology and Application
1	x					Computing system implementation in data center (new hardware / software, IT security review & compliance)
2	x					Network planning and engineering - coverage studies, technology selection, field testing & engineering
3	x					Update work management interface to process additional volume of meter changes, data scripts
4	x					New information management software applications
5	x					Development and installation of interfaces to core utility systems (CIS, EMR, OMS, OIS, EAI, SAP, etc.)
6	x					Develop and process dynamic rates in CIS billing systems
7	x					Exceptions processing (develop, update, and execute data cleanup routines)
8	x					Ongoing IT system operations & maintenance (usage, software, internet application)
9	x					Ongoing data storage and handling costs / incl test, QA environments, business continuity, disaster recovery
10	x					Server replacements (every 3-4 years) for 15 year life cycle
11	x					Records - databases, drawings of field network and data center servers
12	x					Aggregating, validating and creating billing determinant data for electric billing
13	x					Data center facilities
14	x					Data center system performance monitoring and management

Customer Services

1	x					Customer education of rate changes / customer communications campaign
2	x					Out-bound communications (mass media costs, e.g., print, radio, TV) . /CPP or other rate notifications
3	x					Additional rate analysis due to multiple TOU options.
4	x					Customer records / billing and collections work associated with roll-out of meter change process
5	x					Increased call center activity during transition from existing to new rates / meter change appointments
6	x					Process meter changes for new meter installations and DA accounts
7	x					Customer support for internet based usage data communication
8	x					Modification and customer support costs for CIS and other system changes
9			x			Cost of complying w/ regulations - providing alternative safety measures (due to removal of electric mtr readers)

Management and Other Costs

1	x					Overall project mgmt costs (and overhead) including customer service, IT and other functions
2	x					Buy out of Current ITRON Contract for 2000 ERT Deployment (350K meters)
3	x					Impacts of early removal of assets (existing meter inventory - stranded investment)
4	x					Cost of stranding existing utility systems (legacy systems, other)
5			x			Risk contingencies (e.g., technology obsolescence / reliability)
6	x					Meter RFP process and contract finalization and administration
7	x					Employee training for deployment and O&M of new systems, rate structures, etc.
8	x					Training for other traditional classifications (records, call centers, meter readers, T-men, etc)
9	x					Work management tools
10	x					Meter reader reroute administration (assuming gas mtrs are not included - will continue to be read)
11	x					Recruiting of incremental workers
12	x					Supervision / overhead of contracts and technology personnel assigned to hardware and systems development
13	x					Employee communications and change management
14	x					Customer acquisition and marketing costs
15	x					Capital Financing costs
16			x			Cost of increased load during mid-peak and off-peak periods
17			x			Cost of shifting costs from C&I customers to individual ratepayers
18	x					Customers access to usage information through communications meduim

Gas Service Impacts (If included)

x					Gas Index / Module Purchase
x					Aggregation / Validation of monthly / hourly reads for gas billing
x					Replacement of gas meter module, battery purchases and replacement labor
x					Warehousing operations for gas modules
x					Performing atmospheric corrosion inspections (currently performed by meter readers)
x					Energy diversion or safety inspection of service and meter facilities on some periodic basis (currently MRs)
x					Purchase / replacement of non-retrofittable gas meters
x					Increased O&M on gas meters / modules due to addition of electronic modules
		x			Cost of complying w/ regulations - providing alternative safety measures (due to removal of gas mtr readers)

Appendix D
AMI Potential Benefits Categories

AMI Potential Benefits List

Short Term	Long Term (Quantifiable)	Long Term (Not Yet Quantifiable)	Out-of-Scope	Not Quantifiable (Qualitative Consideration)	
					System Operation Benefits
x					Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)
x					Field service savings (turn-on's / turn-off's)
				x	May provide ability to ID active accounts for metered accts not being billed, broken meters, wrong multipliers
				x	Some energy theft easier to identify
x					Phone Centers - Reduced FTEs in the long term due to anticipated lower cust call volume (estimated / disputed bills)
				x	Possible productivity enhancement / rate changes simplified / possible reprogram rather than mtr change
x				x	Outage management benefits (momentary checking for PG&E)
				x	Better meter functionality / equipment modernization
				x	Remote service connect / disconnect
x					Meter accuracy
x					System planning design efficiency
					Customer Service Benefits
x					Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates “lock-outs”
x					Early detection of meter failures
				x	May provide additional opportunity to inspect panel, reattachment of unsecured mtr boxes, ID any unsafe conditions
x					Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing
				x	Customer energy profiles for EE / DR targeting (marketing)
				x	Customer rate choice / new rate options
				x	Customized billing date
				x	Energy Information
				x	Enhanced billing
				x	Load Survey
				x	On-line bill presentment with hourly data / more timely and accurate information about electricity / info access
				x	Lower customer bills
				x	Value to customers of more timely & accurate bills
					Demand Response Benefits
	x				Procurement cost reduction - deferral of capacity, consumption shift to off-peak and/or reduction, lower net emissions
	x				System reliability adder (capacity buffer)
				x	Dynamic fuel switching / Dynamic integration of conventional and distributed supplies
		x			Avoided / deferred transmission and distribution (T&D) additions / upgrade costs
					Management and Other Benefits
x					Reduced equip and equip maint costs (software maint & system support, handheld reading devices, uniforms, etc.)
x					Reduced misc. support expenses (including office equipment and supplies)
x					Reduced battery replacement / calendar resets / meter programming
				x	Reduced meter inventories / inventory management expenses due to expanded uniformity
x					Summary billing cash flow benefits (existing customers)
x					Possible reduction in "idle usage", meter watt losses - at the very least quicker resolution of idle usage episodes
			x		Possible new rev source / new business ventures / new products & srvs / web based interval & power-quality data
				x	May facilitate ability to obtain GPS reads during mtr deployment-improving Franchise & Utility Users Tax processes
				x	Tariff planning - more flexibility of rate contacts & options within standard customer rate classes / dynamic tariffs
		x			Potential for Federal investment tax credits